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GAS INTRUSION INTO SPR CAVERNS

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ABSTRACT

The conditions and occurrence of gas in crude oil stored in Strategic Petroleum Reserve, SPR, caverns is characterized in this report. Many caverns in the SPR show that gas has intruded into the oil from the surrounding salt dome. Historical evidence and the analyses presented here suggest that gas will continue to intrude into many SPR caverns in the future. In considering why only some caverns contain gas, it is concluded that the naturally occurring spatial variability in salt permeability can explain the range of gas content measured in SPR caverns. Further, it is not possible to make a one-to-one correlation between specific geologic phenomena and the occurrence of gas in salt caverns. However, gas is concluded to be petrogenic in origin. Consequently, attempts have been made to associate the occurrence of gas with salt inhomogeneities including anomalies and other structural features.

Two scenarios for actual gas intrusion into caverns were investigated for consistency with existing information. These scenarios are gas release during leaching and gas permeation through salt. Of these mechanisms, the greater consistency comes from the belief that gas permeates to caverns through the salt.

A review of historical operating data for five Bryan Mound caverns loosely supports the hypothesis that higher operating pressures reduce gas intrusion into caverns. This conclusion supports a permeability intrusion mechanism. Further, it provides justification for operating the caverns near maximum operating pressure to minimize gas intrusion.

Historical gas intrusion rates and estimates of future gas intrusion are given for all caverns.

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I Executive Summary

This report is a collaborative effort to study the conditions and occurrence of gas in crude oil stored in Strategic Petroleum Reserve, SPR, caverns. Many caverns in the SPR will potentially require the removal of gas to make the oil deliverable. Historical evidence and the analyses presented here suggest that gas will continue to intrude into many SPR caverns in the future.

In considering why only some caverns contain gas, it is concluded that the naturally occurring spatial variability in salt permeability can explain the range of gas content measured in SPR caverns. Further, we have found that it is not possible to make a one-to-one correlation between specific geologic phenomena and the occurrence of gas in salt caverns. However, we have found that gas is petrogenic in origin. Consequently, it is prudent to attempt to associate the occurrence of gas with salt inhomogeneities including anomalies and other structural features.

Two scenarios for actual gas intrusion into caverns were investigated for consistency with existing information. These scenarios are gas release during leaching and gas permeation through salt. Of these mechanisms, the greater consistency comes from the belief that gas permeates to caverns through the salt.

A review of historical operating data for five Bryan Mound caverns loosely supports the hypothesis that higher operating pressures reduce gas intrusion into caverns. This conclusion supports a permeability intrusion mechanism. Further, it provides justification for operating the caverns near maximum operating pressure to minimize gas intrusion.

Estimates of future gas intrusion rates are given for all caverns. We believe that the existing gas content of oil currently in storage is the best basis for estimating future intrusion rates. It is recommended that at least four caverns at Bryan Mound will need to be watched carefully in addition to judicious monitoring at Big Hill and Bayou Choctaw. The caverns at West Hackberry appear to have lower gas intrusion based on the current estimates.

II Introduction

The United States Strategic Petroleum Reserve, SPR, is currently storing more than 590 million barrels of crude oil to buffer shortfalls in foreign oil, with plans for increasing the storage to 750 million barrels. The oil is stored in sixty-two underground solution mined (leached) caverns and one converted mine in Gulf Coast salt domes. The Reserve has been increasing steadily in volume since the late 1970's, with some of the oil having been in storage for nearly 16 years.

Seveneighths of the oil is currently stored in leached salt caverns, located some 2000 to 4000 feet below the surface. Salt caverns were selected for storage because of their ease of construction (solution mined), low cost, and their impermeability to oil penetration, thus assuring long-term integrity. The existence of gases within the salt domes was unquantified and not well understood even among salt miners. Gases were known to exist in domal salt, where salt mines have typically been declared "gassy" for underground mining activities. The observed gases have been dominated by methane with much smaller quantities of carbon dioxide and other gases.

The existence of gas in SPR wells and caverns has been observed over many years. "Frothy" oil has been observed during integrity testing and gas has been released during leaching. Indications of gas in the oil have been of interest historically but not felt critical since any physical effects of the gas have always been mitigated by judicious engineering. Furthermore, the major quantity of stored oil was not materially affected and refineries could accommodate oil with trace amounts of gas. However, over time the gas content of SPR oil has increased (discussed in this report), the EPA has reduced the quantities of regulated gas that can be released, and sampling instrumentation has become available which facilitates accurate data collection. At cavern oil-storage pressures, typically 1000 to 2000 psi, gas is readily absorbed and retained in crude oil. During oil withdrawal, oil is transferred through reduced-pressure surface pipelines and tanks, thereby releasing the gas. This released gas may exceed EPA emission standards for tanks and safety limits for handling. Such limits and standards are sufficiently low that some oil stored at three SPR sites is already approaching or is above such limits. It is important, therefore, to understand the potential mechanisms and conditions for gas intrusion into the oil. This understanding may lead to development of a predictive capability for gas intrusion and will allow for planning, mitigation, or prevention.

Gas in domal salt has been known to occur routinely. Salt miners have encountered pockets of gas, known as "blowouts", and most domal salt mines in Louisiana have been declared "gassy" by the Mine Safety and Health Administration (MSHA). Quantities of gas experienced have varied widely with little quantitative understanding resulting. The composition of the gas has been dominated by methane, with measurable quantities of carbon dioxide and lesser amounts of other gases. The distribution of gas within a dome is known to vary appreciably, with mines generally encountering more frequent intercrystalline pockets of gas at greater depths and in the proximity of fault zones, anomalous zones, or the periphery of the dome. Gas is also known to exist within crystalline salt to a much lesser degree.

The migration of gas through the salt matrix has been measured near excavations. Permeabilities of salt have been measured over the years as reported in Appendix 1. There is a strong belief that salt is much less permeable than the actual measurements and that the measured permeabilities really reflect the limitations of the equipment. This belief is supported by the observation that measured salt permeabilities have become progressively lower as equipment and techniques have advanced. For example, as shown in Appendix 1, in 1960 the permeability of domal salt at Tatum was reported as 10^{-14} to 10^{-16} m^2 while in 1990 the permeability measurements of salt from Asse, Germany were 10^{-18} to 10^{-20} m2.

It is also known that salt which has been confined historically at great pressure may undergo dilation when subjected to deviatoric stresses of sufficient magnitude. Ehgartner postulated a dilation model to address this phenomena in Appendix 2. For cavern stresses, no evidence was found to suggest large permeability changes resulting from damage of the salt surrounding caverns. Nonetheless, enhanced permeabilities resulting from stress relief are observed in underground openings such as the wet drift at Weeks Island (discussed below).

Non-uniform or anomalous zones (extensive impure salt volumes with other evaporites and/or sediments) within the salt mass also exist. The zones are extensive rock volumes often occurring as planar elements. The larger zones at Weeks Island have been mapped underground and corresponding expressions found in caprock and surface expressions. Some anomalous zones have been interpreted as faults, and within salt mines these zones have been mapped. They have also often been inferred from well data and geophysical data. These zones are observed to be more permeable within mines. They may be a source of gas or other fluids. The site characterization reports of domes within the SPR show anomalous zones which intersect caverns directly (Neal et al, 1993). The role of such zones as a source for absorbed gas in oil is considered below.

In summary, efforts have been initiated by the Department of Energy to understand more about the phenomena of gas intrusion into oil storage caverns. Factors that might affect the rates of intrusion are of high interest, since conceptually such factors might be controlled to reduce the quantity of gas absorption. This report discusses the possible mechanisms of gas entry into caverns, establishes some limitations, and draws a qualitative conclusion with recommendations for better quantifying absorption rates.

III Gas Migration Concepts

Two concepts are postulated for explaining how natural gas intrudes into oil storage caverns. Because there is limited experimental evidence, the ideas presented in this section are hypothetical and generally not verified. These concepts are examined for consistency and for agreement with other known phenomena so that we are able to judge the merits of each idea. The two concepts are as follows:

(1) gas release during leaching, and
(2) gas permeation through inhomogeneous salt.

III. A. Gas Release During Leaching

This concept deals with the release of gas from the salt during the solution mining. This idea postulates that the salt is to be considered essentially impermeable and the primary mechanism of gas release is from the dissolution of the salt matrix. The gas released during cavern leaching is presumed to be transferred to the blanket oil or to oil stored above the brine during leach-fill operations. Subsequently this oil is diluted as more oil is added to fill the cavern. This mechanism assumes that gas is present in the salt to be leached. Under this mechanism, blanket oil following leaching would contain a great deal of gas. The total gas content of the cavern following oil fill would then be stable although mixing would continue. Hence, if this mechanism is of primary importance, the primary gassification of oil would take place during oil fill and presumably little additional gas transfer would occur.

In considering the validity of this mechanism, its characteristics and implications are examined. This concept assumes that the gas found in stored oil is released from the salt matrix during leaching and concentrated in the blanket oil. Support for this mechanism comes from the high affinity for oil under pressure to absorb gas, and the lower affinity for gas absorption in brine. Additionally, gas traps in mines also suggest that this mechanism is reasonable. Supporting proof for this mechanism should be an extremely high gas content in the blanket oil following leaching, no long-term increase in overall gas content following oil storage, no dependence on operational pressure of the quantity of gas within the oil, minimal gas release in wells before leaching, and no gas in most Phase I caverns which were not leached by the SPR. Next, we will examine the consequences of this mechanism for consistency with known phenomena.

IIIA. 1. Inconsistencies Associated With the Mechanism of Gas Release During Leaching

IIIA.1.a. Observed GOR of oil blankets

In the calculations below the volume of blanket oil is assumed to be equal to a nominal value of 10000 BBL. In order to obtain a Gas-Oil-Ratio (GOR) of 4 SCF /BBL in a 10 million barrel cavern, a simple dilution of the blanket oil would require the blanket oil to have a GOR of 4000 SCF/BBL. This very high gas content would have to exist in oil stored at 1400 psi. At this pressure, this GOR exceeds the equilibrium concentration of methane (the primary component of natural gas) in oil (approximately 300 SCF/BBL) by a factor of 13. Other components in the oil, such as nitrogen, further reduce the gas solubility in the oil so that these estimates are conservative. Further, GORs of this magnitude have never been observed within the SPR. At the Big Hill SPR site, observed blanket oil concentrations of gas were of the order of several tens of SCF/BBL. This is far below the concentration required to credibly validate this mechanism.

IIIA.I.b. Methane Equilibrium Between Oil and Brine Phases

A second consideration for the mechanism of gas release during leaching is the gas equilibrium between the oil and brine in the cavern. For gas released during leaching we consider the following calculation: Based on mine measurements, the amount of gas in salt is nominally less than or equal to 1 SCF/BBL of salt (see Appendix 5), although local variations may exceed this value. In leaching a 10 million barrel cavern, then approximately 10^7 SCF of gas would be released. This gas will tend to partition between the blanket oil and the brine used to leach the cavern.

In order to determine how gas will be divided between the oil and brine streams, both equilibrium and fluid quantities are considered. The equilibrium concentration of methane in oil is approximately 300 SCF/BBL at 80 °F and 1400 psi (Engineering Data Book). At the same conditions the equilibrium concentration of methane in water is 3 SCF/BBL (Perry). Hence, the equilibrium of methane between oil and brine will tend to concentrate the methane by 100 fold in the oil phase. Additionally, 70 million barrels of brine are nominally required to leach a 10 million barrel cavern with about 10,000 BBL of blanket oil used in SPR caverns. Therefore, the ratio of brine used to leach the cavern to the blanket oil can be simplified to:

$$\frac{70{,}000{,}000 \text{ BBL brine}}{10{,}000 \text{ BBL blanket oil}} = \frac{7000 \text{ BBL brine}}{\text{BBL blanket oil}}$$

Combining both quantities and concentration effects, the ratio of mass of methane in the brine phase to the mass of methane in the oil phase is:

$$\frac{\text{Mass of methane in brine}}{\text{Mass of methane in oil}} = \frac{\text{Concentration of methane in brine}}{\text{Concentration of methane in oil}} \times \frac{\text{Volume of brine}}{\text{Volume of oil}}, \text{ or}$$

$$\frac{\text{Mass of methane in brine}}{\text{Mass of methane in oil}} = \frac{1}{100} \times \frac{7000}{1} = 70$$

The effect of this partition of methane between brine and oil is that the vast majority of the gas liberated by the salt ends up in the brine exiting the cavern. Considering the approximately 10^7 SCF of gas released during cavern formation and the partition of methane between brine and oil, the amount of gas computed to remain in the blanket oil is

$$\frac{10^7 \text{ SCF gas}}{(70)\,(10^4 \text{ BBL blanket oil})} = 14 \text{ SCF/BBL}.$$

This amount of gas in the blanket oil is in approximate agreement with blanket oil concentrations observed at Big Hill. Further, when this blanket oil is diluted further with 10 million barrels of oil, the blended gas concentration is projected to be about 0.01 SCF/BBL. Even if the amount of gas in the salt is several orders of magnitude above the norm, the resultant concentration of gas in the oil is still only 1 SCF/BBL. It is thus concluded from equilibrium considerations that the mechanism of gas release during leaching is a minor effect.

IIIA. 1. c. Mass Transfer Rate Effects on the Methane Equilibrium

A subsidiary consideration to the equilibrium calculations in the previous section, IIIA.l.b., is whether the rate processes actually allow equilibrium to be achieved. A scoping calculation of the mass transfer rate processes of gas partition between oil and brine was performed to indicate that near equilibrium is very likely achieved.

To determine equilibrium conditions, we calculated the rate of the transfer of methane from the oil blanket to the leach water. For this computation it was assumed that the gas content of the oil in the blanket was artificially elevated to 100 SCF/BBL and the time required to lower the gas content to 14 SCF/BBL was determined. It was also assumed that newly added leach water entered the cavern through the hanging string and rapidly moved upward to the oil interface. Fluid flow was then radially outward and then down at the salt wall. When this water contacts the blanket oil, the gas from the oil is transferred to the water. The rate of mass transfer is computed using Equation 17.5-17 (Bird et al, 1960, p. 540). From this analysis it is determined that the time required to reduce the gas concentration in the blanket oil to 95% of its initial concentration is measured in a few days. This short time suggests that gas equilibrium between the oil phase and the water phase should be presumed to exist.

III.A.1.d. Gas Content in Phase I Caverns

An additional inconsistency arises with the concept of gas release during leaching with gas content observed in Phase I caverns. The Phase I caverns in the SPR were purchased rather than being leached, the blanket oil was exchanged and then the caverns were filled with oil. According to the gas release during leaching mechanism, these caverns should contain little gas since there was little additional leaching. However, as noted in Tables l-4 some of the Phase I caverns (those caverns with designation numbers less than 100) have significant quantities of gas.

III. A. 2. Summary of Gas Release During Leaching Mechanism

While it is known that gas is trapped in salt porosity and that leaching should free that gas to subsequently dissolve into the oil stored in a cavern, the effects noted above suggest that the extent of contamination by this mechanism is small. This effect by itself appears insufficient for explaining the observed gas content in gassy caverns. The combined evidence of observed GORs of blanket oil, the expected gas-oil-water equilibrium, the rapid mass transfer rates, and the observed gas content of Phase I caverns points to the relative unimportance of this mechanism.

III.B. Gas Permeation through Salt

This mechanism of gas permeation through salt assumes that: 1) gas-containing pores and gas pockets exist in the salt, 2) the pores are initially pressurized to lithostatic pressure, and 3) the salt surrounding a cavern has a non-zero permeability. This permeability is also assumed to be heterogeneous. The creation of a cavern and the subsequent lowering of the pressure exerted on cavern walls is presumed to cause flow of gas into the cavern. As with the first mechanism, we will examine the assumptions of this scenario for logical consistency.

III. B. 1. Stress Induced Permeability Changes in the Salt Surrounding SPR Caverns

In 1985 and 1986, in support of the SPR, compressed air/tracer gas studies were performed in the wet drift at Weeks Island (Lagus et al., 1986). The Wet Drift was isolated from the rest of the mine and a tracer gas was released into this confined space. Substantial concentrations of tracer gas were observed in close proximity to the Wet Drift Bulkhead almost immediately upon tracer gas pressurization of the Wet Drift. The immediate observation of tracer presence on the other side of the bulkhead leads one to the conclusion that fractures had developed through the homogeneous, relatively impermeable salt around the bulkhead. These fractures were the result of creep in the salt near the drift openings, yielding a dilatent, disturbed rock zone.

In relatively shallow underground openings, such as mines, the effect of creep in enhancing permeability as in the Wet Drift is well documented. In SPR caverns however, the internal fluid pressure and the round geometry of the caverns create a more favorable stress environment. Ehgartner (Appendix 2) modeled permeability changes in a fluid filled cavern using the dilatancy criteria of Van Sambeek et al. (1993). Under this criteria, no permeability increase is anticipated for damage factors, D, less than one. In fluid filled caverns, however, the confining stress at the wall is much higher than in a mine. Ehgartner found that the highest damage factor in a cavern was 0.59, occurring in a cavern immediately following a workover when surface oil pressure was dropped to zero. A considerable reduction in the damage factor was noticed when operating at normal operating pressure (D = 0.40). Modeling of the Weeks Island Mine with this criteria reveal damage factors greater than one. These analyses suggest that salt surrounding a cavern is not <u>measurablv</u> dilated due to stress perturbations that result from creating and operating an SPR cavern. It follows that without significant dilation of the salt, significant increases in gas permeability are unlikely. Permeabilities accompanying measurable dilatation in salt are on the order of six magnitudes greater than that of intact or nondilated salt.

III. B. 2. Permeability Considerations in SPR Caverns

Since stress effects in SPR caverns do not appear to significantly increase the salt permeability, we next examine the unaltered permeability of an intact salt matrix. Historical measurements of permeability in domal salt suggested that intact salt was reasonably permeable. Measurements performed in 1963 showed domal salt permeability to be approximately 10^{-14} to 10^{-16} m^2 (10 to 0.1 mD) (See Appendix 1). As techniques have improved, however, these values have steadily decreased until 1990 measurements of domal permeability were 10^{-18} to 10^{-21} m^2 (1 to 0.00 1 D). Thus, the permeability of undisturbed salt, as defined by our ability to measure it, may approach salt diffusivity for intact salt under a hydrostatic stress state where no deviatoric or shear stresses exist. Because the measured value of the permeability of an intact salt matrix may decrease further below these values, let us consider a more general parametric study of methane intrusion through salt where permeability is varied.

III. B. 3. Permeability Modeling

Ehgartner (see Appendix 3) performed a series of scoping calculations to simulate gas inflow into an SPR cavern using a permeability/storage model. The permeability selected for this analysis was varied around 10^{-21} m^2 (0.001 D) and the porosity was 0.01. The resultant gas flow into an SPR cavern is shown in Figure 1. From this figure the model predicts that at a permeability of 10^{-21} m^2, the amount of gas which intrudes into a cavern is 2 SCF/BBL over the first 10 year period. This rate is found to decrease by about 50% over the second ten year time period. This intrusion rate approximates the actual gas intrusion rate for many SPR caverns. A higher permeability typically predicts too much inflow while a lower salt permeability does not show enough. Hence, we conclude, based on the measured gas content of the oil only, that an average salt permeability of approximately 10^{-21} m^2 may explain the intrusion of gas into caverns.

The source of gas for the permeability intrusion model was assumed to be gas contained within the salt itself. This gas was contained at lithostatic pressure and flowed toward the lower pressure hydrostatic environment of the cavern where it was presumed to be absorbed by the oil. As time progressed the salt near the cavern became depleted of gas, and as a consequence, the rate of inflow decreased. It is also noted that this permeability model gives a time dependence that is in general agreement with a standard reservoir depletion curve.

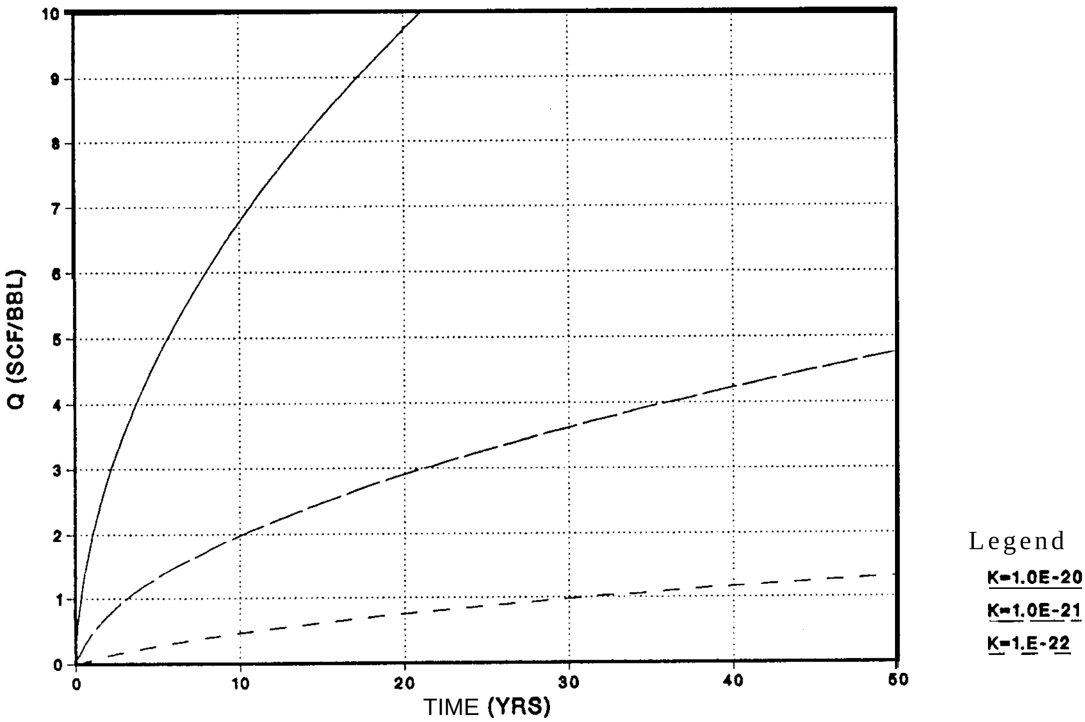

Figure 1. Plot of gas flow into an SPR Cavern for salt matrix permeabilities of 10^{-20}, 10^{-21}, and 10^{-22} m^2. The total amount of gas intrusion, Q, is measured in SCF of intruding gas per barrel of oil in a cavern. Note that Q is less than the gas-oil ratio because the intruding gas will strip other gases out of the oil as a consequence of dropping the pressure during the measurement of GOR.

Observations and measurements from various SPR wells prior to solutioning of caverns show significant quantities of gas can be present initially. The delayed development of Big Hill wells 106 through 110 A and B provided an opportunity to monitor pressure buildup over time (Beasley and Goin, 1986). Ehgartner (Appendix 8) concludes that the pressurization rate in the wells at that time (1 to 8 psi/day) were dominated by gas releases from the salt. This can be expected from the permeability model and the fact that the gas intrusion and hence pressurization rates decrease with time. Currently, the caverns at Big Hill are pressurizing at less than 1 psi/day which can be attributed to creep and thermal increases. These observations and evaluations support the permeability mechanism and demonstrate that gas inflow varies both spatially (from well to well) and with time.

III. B. 4. Gas Migration Off Dome

One apparent inconsistency with this presumed uniform permeation source of gas is that, to remain consistent, gas must be presumed to migrate out of the dome over geologic time to the sediments surrounding the dome. If we assume hydrostatic pore pressure outside the dome, we can estimate the time required to have trapped gas leak to the surrounding sediments. If the time required for the trapped gas pockets to totally depressure to hydrostatic is less than the age of the dome, then the hypothesis is that gas pockets would be unable to supply gas to a cavern. Our geologic understanding of the Gulf Coast salt domes is that they are about 50 million years old (± 10 - 15 million years). If we use a consistent uniform permeability model as presented in Appendix 3 to consider this gas leakage to the surrounding sediments, we find the total depletion of gas from a salt dome as presented in Figure 2. From this figure we see that all of the overpressured gas in a dome is predicted to be bled down to hydrostatic pressure at 10 million year when the salt permeability is 1 0^{-21} m^2. At higher permeabilities this depressurization of the dome is faster (1 million years) and at lower permeabilities this pressurization is slower (100 million years).

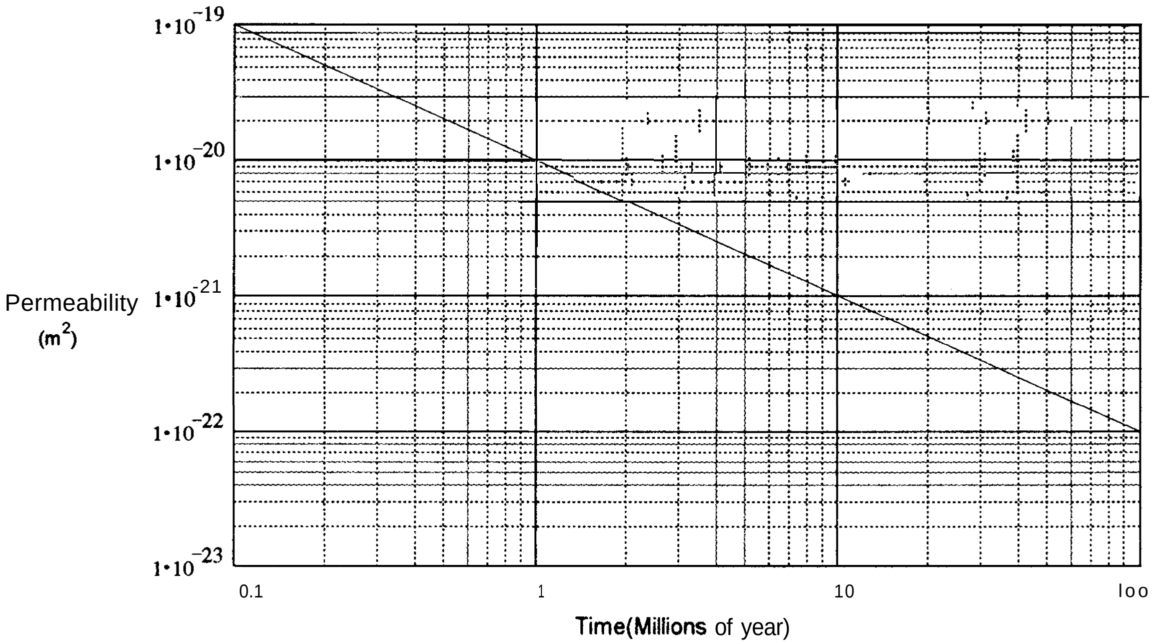

Figure 2. Plot of time necessary to deplete a dome of 2 mile radius as a function of the average permeability of the salt matrix.

III. B. 4.a. Inconsistencies with Gas Migration Off Dome

There are several reasons that the assumptions used in modeling gas migration off dome and gas inflow into caverns should be different. These reasons include the variation of the permeability of the salt in the dome over time, gas pressures in the sediments surrounding the dome in excess of hydrostatic, the spatial variability of the permeability of the salt in the dome.

First, it is possible that the permeability of the dome may have increased over geologic time. When the salt dome arose out of the Louann mother salt at a depth of approximately 5 miles, it may be assumed to have been in a perfect visco-plastic state due to the high temperatures and stresses at depth. It can be postulated that such a fluid-like salt would have a lower permeability than that measured today after stress relief and cooling. Therefore, the appropriate time averaged permeability of the dome may be less than any of those assumed in the bled off calculations. Thus, these considerations suggest that the gas may not have had sufficient time to have completely bled off pressure. Thus, the gas permeation mechanism appears credible. If any partial depressurization of the pores did occur, it could have been compensated by creep closure of the pores as the equilibrium pressure is lithostatic. If pressure compensation through creep closure of the pores did occur, the permeability would likely decrease even farther.

Secondly, it is assumed that the pore pressure in the sediments on the outside of the dome is hydrostatic as determined by the density of the overlying water. While hydrostatic pore pressure may be a common assumption in geohydrologic modeling, the possibility of gas in the uplifted strata that steeply dips along the flank of a dome may challenge this assumption. Pressures in excess of hydrostatic are commonly encountered during oil and gas exploration.

Thirdly, it is interesting to speculate on the spatial variability in permeability throughout a dome. Over geologic time, any brine flow out of the dome would not only depressurize but also cool. Since the brine can be assumed to be saturated, salt would precipitate in the salt pores near the edge of the dome. This would tend to close any existing flow channels and result in a 'skin effect' where a lower permeability may be expected. Such a skin would prohibit or slow gas migration off the dome over geologic time. Another cause for spatial variability of permeability in salt is stress. Large scale permeability changes due to stress induced damage has already been discussed. But on a smaller, as yet immeasurable scale, stress perturbations due to cavern creation and operation may create or alter permeability in salt. It may even be possible that unperturbed domal salt may have a permeability approaching the diffusivity of crystalline salt. Regardless of the mechanism, even homogeneous salt can be expected to have a spatially varying permeability. As such, some caverns can expect more inflow of gas than others. Hence, the intrusion mechanism of gas permeation through the salt has been shown to predict reasonable gas intrusion quantities over a range of permeabilities considered as representative for salt.

III. B. 5. Gas Permeation Through Specific Features and Anomalous Zones

In addition to the matrix intrusion concept, the permeability model presented above may also be used to describe permeable intrusion through specific features. These specific features include anomalous zones, faults, and fractures, all of which could be expected to have higher gas permeabilities than intact salt. As individual caverns intercept these features, gas may permeate to the stored oil. In terms of the permeability flow model, anomalous zones, faults, or fractures are merely heterogenieties to be explained by the same model.

III. B. 5.a. Uncertainties of Anomalous Zone Transport

As is discussed in the geological correlations section of this report (Section IV), there is a lack of correlation between known anomalous zones and the gas content of SPR caverns. Despite this deficiency, the mechanism is a possibility. Since it is presumed that there are anomalous features that have not been mapped, it is likely that there could be interceptions of these features with caverns where surface expressions may be minimal. For this reason we find no major inconsistencies with this mechanism.

III. B. 6. Effects of Operating Pressures

A consequence of the gas permeability model (i.e., flow through salt, fractures, or anomalous features) is that an increase in cavern operating pressure would result in a decrease in the gas inflow as the pressure gradient driving force is reduced. Accordingly, we looked at the possibility of finding a correlation between the average lifetime operating pressure of several caverns at Bryan Mound and the measured gas content of the oil stored in respective caverns. A study of the lifetime average operating pressure versus gas content was completed (Appendix 4). In practice, accurate determination of the average operating pressure for a cavern is complicated because often a complete daily pressure history is not available. Difficulties not withstanding, a review of historical operating data for five Bryan Mound caverns supports the contention that higher operating pressures will reduce gas intrusion into SPR Bryan Mound caverns. The main results of this study are presented in Figure 3. From this figure the effect of operating pressure is not strong but the tendency is still observed. The scatter in the data presented is primarily a result of the uncertainty in the gas content determinations of Section V and of the operation of other factors not included on this plot. In addition to the cavern data we have also presented a projection of the variation of inflow with operating pressure according to the salt permeability model. While this line is placed to approximately match the gas intrusion rates, the pressure dependence follows from the model assumptions. The significance of this result is that it tends to corroborate the assumptions of the permeability model. As a side observation, it also provides justification for operating caverns at the maximum allowable operating pressure.

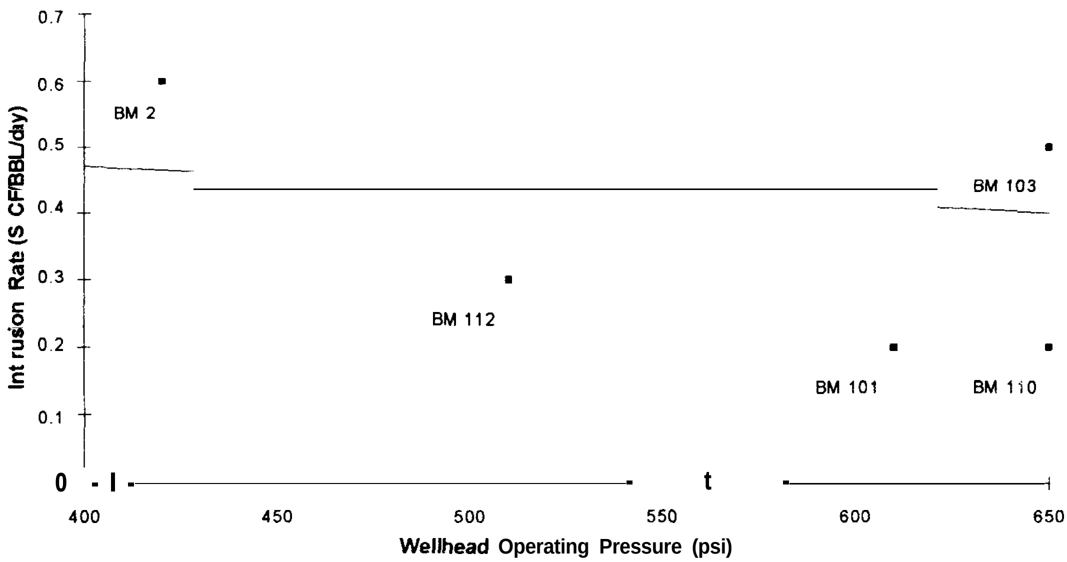

Figure 3. Plot of intrusion rate for Bryan Mound Caverns 2, 10 1, 103, 110, and 112 versus wellhead operating pressure. The line in this figure shows the variation in inflow rate with operating pressure as determined from the permeability model.

IV Geological Correlations

IV.A. Source Term Considerations

In Figure 4 Giles (see Appendix 5) has plotted the isotopic composition of gas liberated by crude oil stored in the SPR and also gas liberated from the host rock. In this study the origin of the gas is determined by the methane stable isotopic ratios, C^{13}/C^{12} and H^2/H^1. On such a plot several regions are defined which establish whether a gas is petrogenic (thermally or geologically derived) or biogenic (marine or microbially derived) in origin. In all samples of oil obtained from SPR storage caverns, it was determined that the gas is definitely not biogenic; in most cases the gas composition is firmly in the petrogenic region. In Appendix 5 Giles discusses other issues with importance to the gas content increase of SPR caverns.

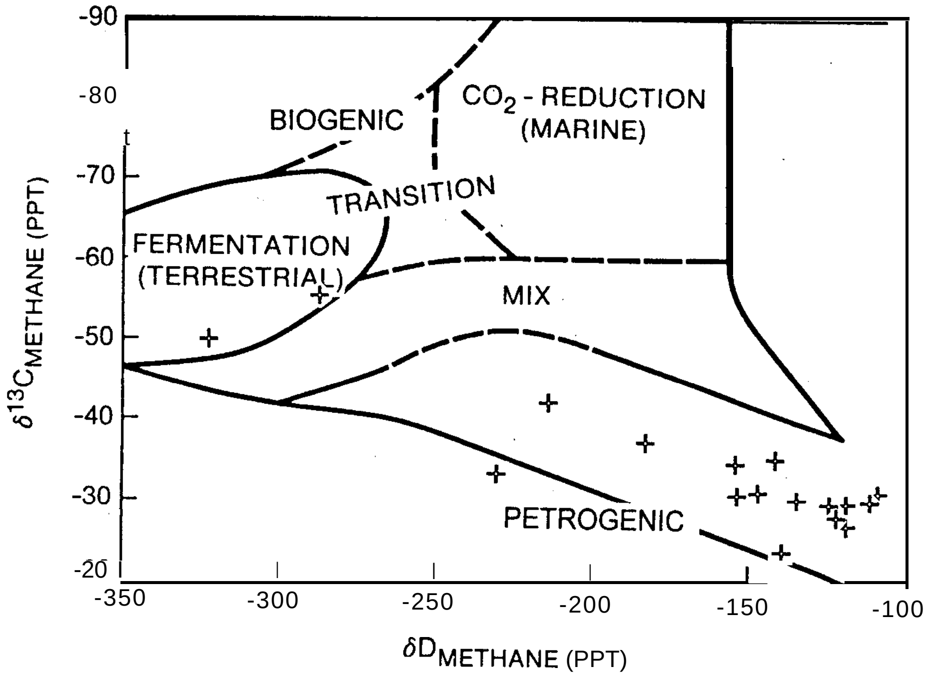

Figure 4. Plot of stable isotope ratios for carbon and hydrogen in methane obtained from SPR caverns.

IV. B. Geologic Considerations

Because the majority of gas samples were petrogenic in origin, it is logical to associate geologic features with the occurrence of gas. Appendix 6 provides a summary and assessment of information on the presence of gas in salt domes as it relates to crude oil storage in caverns. All except one (Avery Island) of the "Five Islands" rock salt mines of south Louisiana have been classified as gassy. These mines have allowed for study of gas in association with salt as noted in Appendix 6. Appendix 6 and Neal (1993) note that geologic features are present in salt stocks that have been associated with the presence of gas in salt. These include insolubles, potash, anhydrite in large amounts, and shear zones. These features are called anomalous features because they are departures from pure salt. These features also have the facility to have greater porosity and permeability than pure salt, and thus can act as reservoirs and conduits for gas. A direct correlation with anomalous features and gas is problematic. Thorns, in Neal et al. (1993), calls attention to the many anomalous features associated with the Bryan Mound site, the caverns there, and the presence of gas. Figure 20 (Neal et al, 1993) shows an anomalous zone (a planar element or band consisting of an alignment and congregation of anomalous features), transecting the dome from northwest to southeast.

Figure 5 reproduces the anomalous features at Bryan Mound as portrayed by Neal et al (1993). Figure 5 shows contours in the gas rise over the last ten years (a measure of gas entry into the Bryan Mound Caverns). An anomalous zone is contained within the region outlined by the "0" contour (Figure 20, Neal et al, 1993). The caverns immediately adjacent to and in the contour are nearly free of gas. Some caverns further away from the zone are gassy. Some of the caverns which have anomalous features associated with them are gassy and some are not. As such, definitive correlations cannot be make, based on existing data.

Similar types of anomalous zone correlations can be attempted for the Big Hill and Bayou Choctaw sites. Figures 6 and 7 contain measures of current gas content compared to interpretations of structural geology (Figure 6: Bayou Choctaw, and Figure 7: Big Hill). For Bayou Choctaw, faults (probable and inferred) in the salt are plotted. Correlations of gas in caverns and proximity to geologic structure are not intuitively apparent, two of the caverns near two east-northeast trending faults are gassy and the other three are not. At Big Hill, faults in the caprock are mapped. It may be inferred that these faults reflect, in some manner, differential displacement (faulting) in the salt. Because it is probable that at least some of the gas in Caverns 106-109 came with transfers of oil from Sulphur Mines their values are not included in the contouring exercise. Because Caverns 107 and 108 both contain a significant amount of gas, are near Cavern 102 (which is also gassy), and are within a highly faulted area, one may be inclined to associate the gas presence with the faulting. This association requires more monitoring to be well founded.

IV. C. Summary of Geologic Correlations

An anomalous feature must be gas bearing, i.e., a source or conduit, for it to be a problem in the context of this report. If an anomalous feature is not a gas reservoir nor a conduit between a cavern and a gas reservoir, then it will not facilitate the presence of gas in a cavern. It should also be noted that although the SPR sites have been mapped and studied through geologic and geophysical methods, it is at best difficult to know the subsurface geology within a salt dome in detail. None of the mechanisms specifically address the observation that gassy caverns tend to be grouped or isolated; non-gassy caverns are located adjacent to gassy ones. Many unknowns yet remain. The source of the gas dictates that there be a geologic cause for its occurrence, thus the search for such correlations is warranted and encouraged in future investigations.

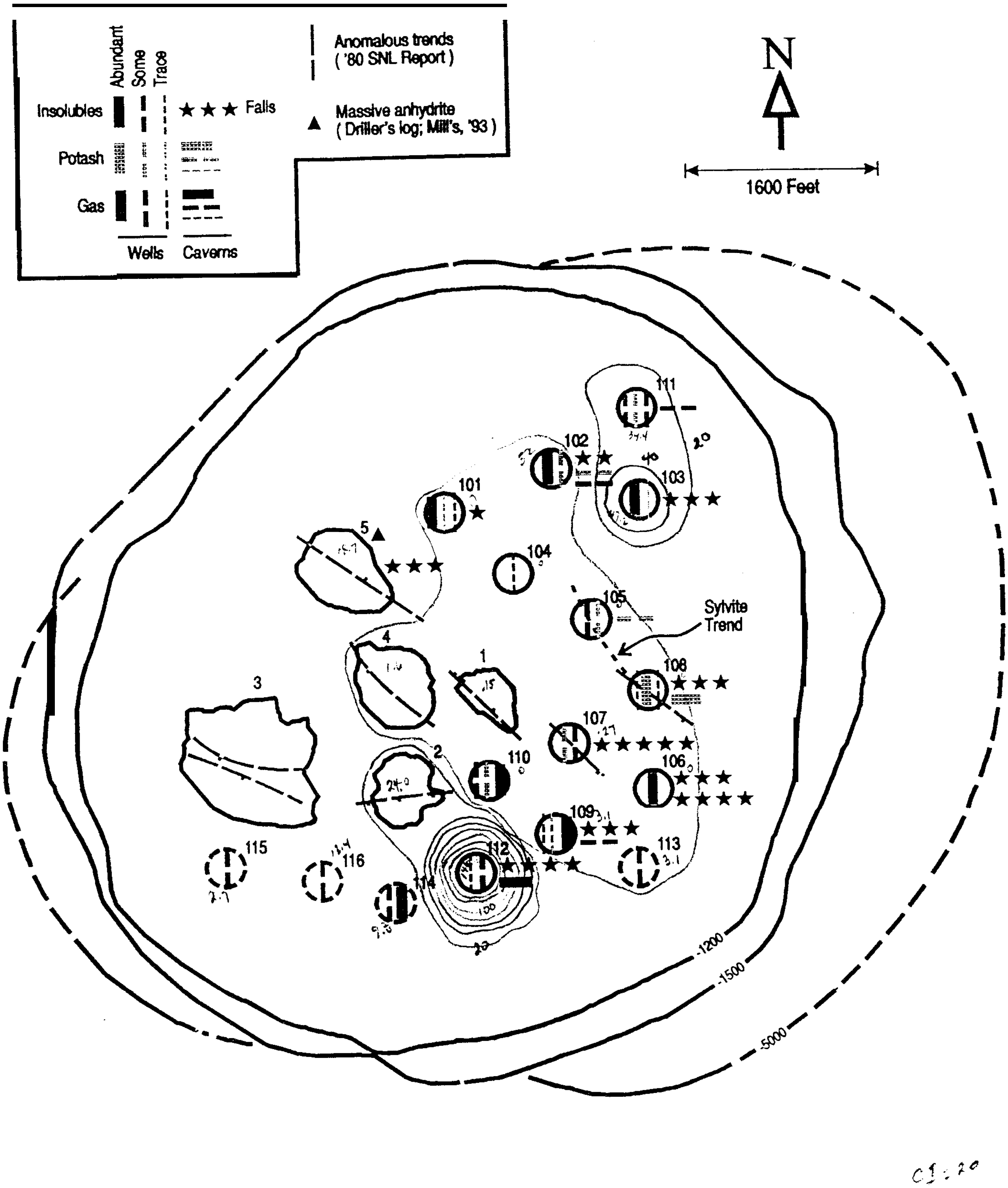

Figure 5. Anomalous features at the Bryan Mound Dome with contours of estimated historical gas rise.

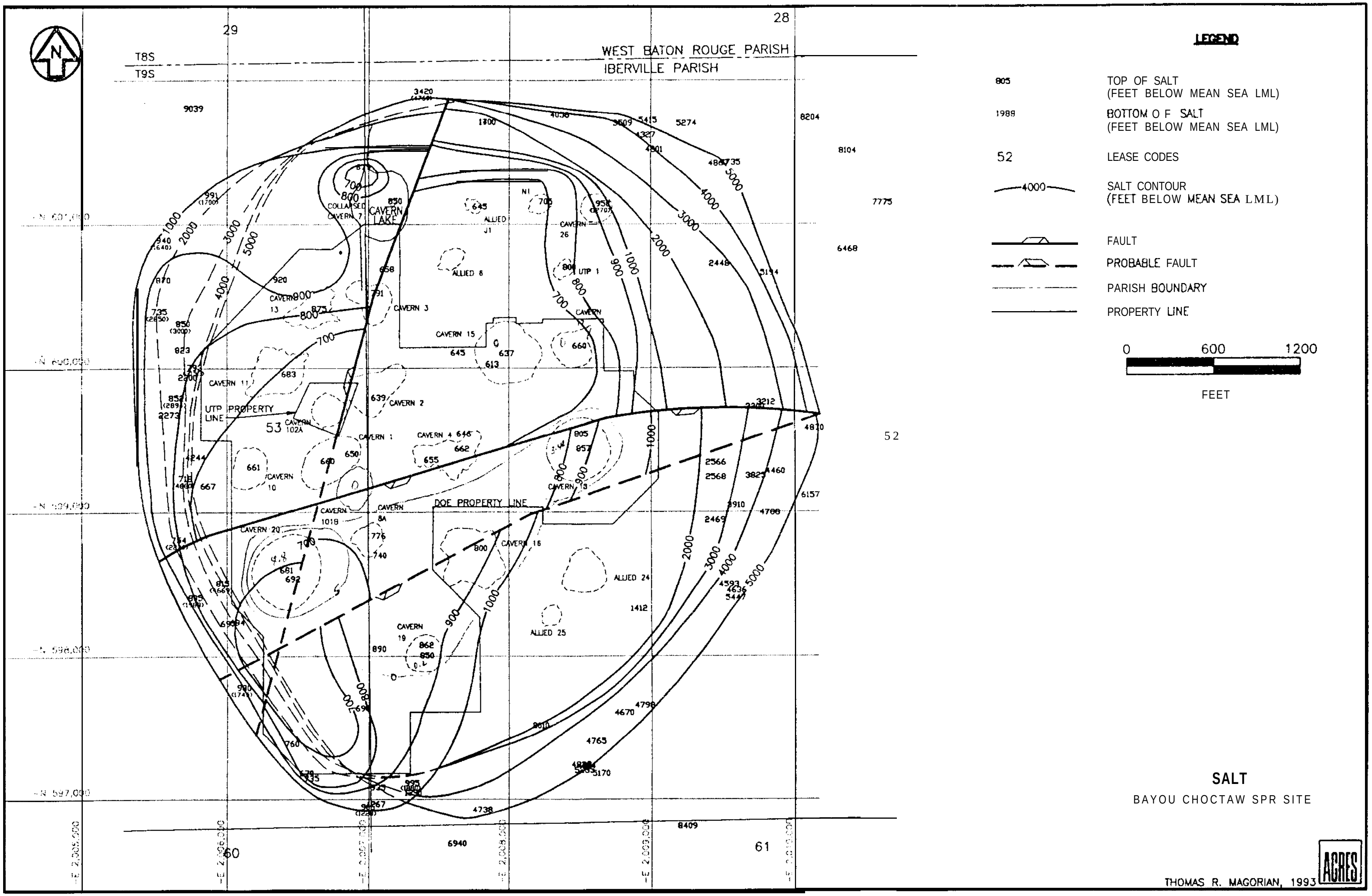

Figure 6. Anomalous features at Bayou Choctaw with contours of estimated gas rise.

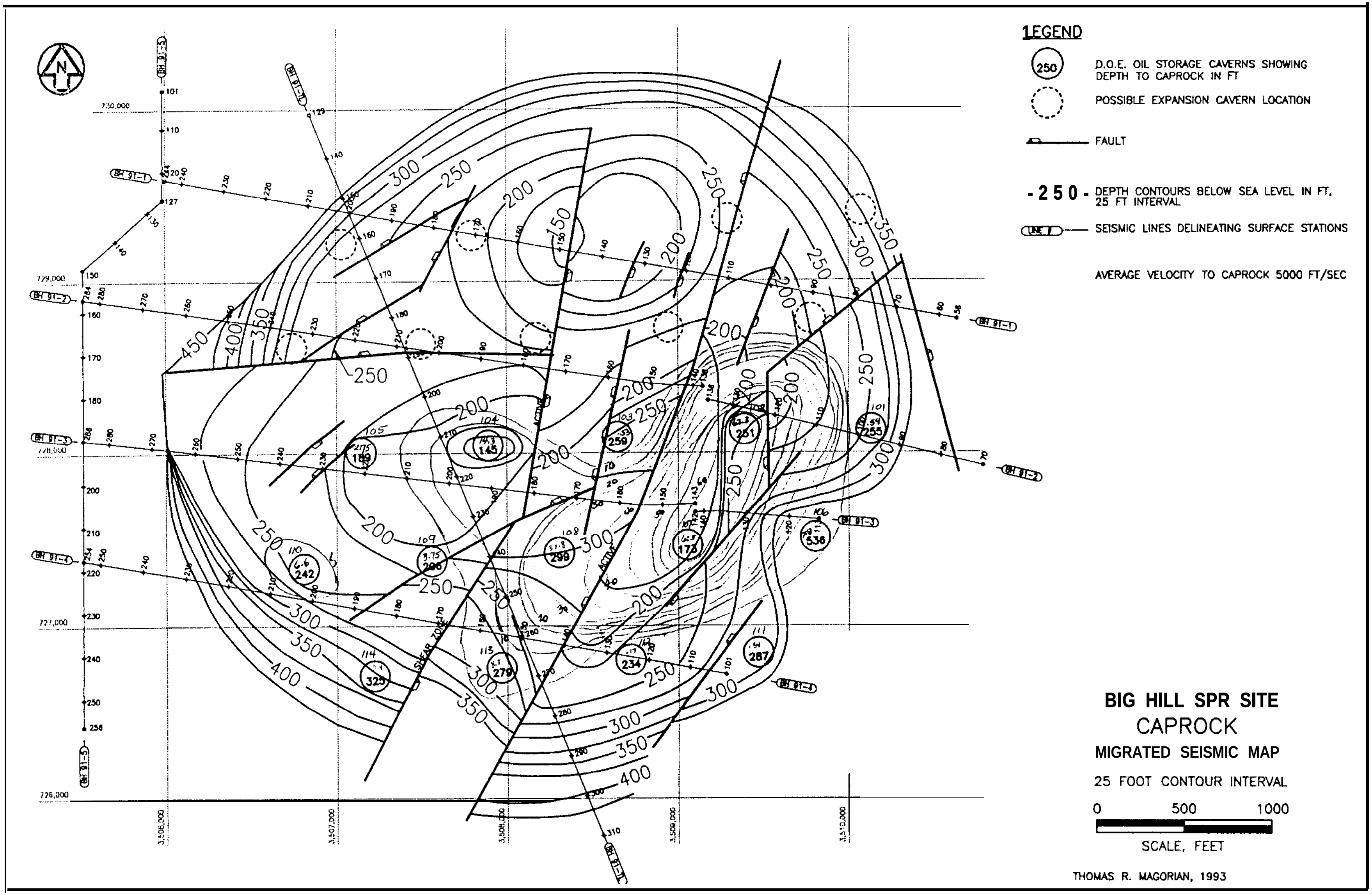

Figure 7. Anomalous features at the Big Hill with contours of estimated historical gas rise.

V Gas Contents of Stored Oils

The gas content of oil stored in SPR cavern has been quantified by two main techniques. In the first of these techniques, pressurized oil samples were obtained with a downhole sampler. These samples were transferred while still pressurized to sample bottles that were remotely analyzed in the laboratory. This method is described as the “pressurized sample method”. The pressurized sample method was used to analyze all of the caverns within the SPR and provided an initial estimate of the cavern gas content (see Appendix 7). These gas content values were compared with measured bubble points and compositions. The comparisons revealed a discrepancy between the composition and the measured GORs and bubble points. Because of these discrepancies, it was necessary to adjust the measured gas contents that were obtained from the pressurized sampling method to compensate for the observed bias. The primary benchmark used to make the adjustments were data obtained from the second method of analysis, the skid-mounted gas separator.

The skid-mounted gas separator was the second method used to gather gas content data on oils from the SPR. In this method oil was piped out of a cavern and through a skid mounted atmospheric separator. Flow rates of gas and oil were measured to allow GORs to be determined. Gas compositions were measured for the off gasses using a gas chromatograph. Finally, the bubble point condition was determined by shutting in the gas stream as the liquid continued to flow. The eventual steady state separator pressure is identical to the bubble point. These data were found to be much more consistent and have now been analyzed for all caverns within the SPR (Appendix 9).

These recent estimates of gas intrusion rates into caverns are summarized in Tables 1 through 4. The basic premise of the gas-intrusion rate calculation is that the gas content of the oil at receipt conditions is zero. Hence, any increase in gas content at the receipt temperature corresponds to gas intrusion. In these estimates the receipt temperature is assumed to be approximately 80°F, and the gas intrusion is referenced to 80°F. Where the total oil volume is small, as in the Big Hill caverns, the estimate of gas intrusion is expected to be inaccurate.

Table 1

BRYAN MOUND GAS INTRUSION RATES

Site	Cavern #	Date of Oil Fill	Date of Sample	Gas Intrusion psi/year @ 80°F
Bryan Mound	2a	Dec-77	Apr-93	0.36
	4a	Dec-77	Jan-94	0.01
	5a	Oct-87	Sep-93	0.02
	101	Aug-83	Feb-94	0.83
	102	act-83	Feb-94	0.11
	103	Mar-83	Sep-93	1.94
	104	Apr-82	Feb-94	0.12
	105	Apr-82	Feb-94	0.12
	107	Feb-82	Feb-94	0.12
	109	A-ug-82	Feb-94	0.62
	110	Dee-8 1	Feb-94	-0.05
	111	Jul-84	Sep-93	1.89
	112	Jun-84	Oct-93	2.22
	114	Jul-87	Jan-94	0.57
	115	Jan-87	Feb-94	0.11
	116	Jan-87	Jan-94	-0.08

Table 2
WEST HACKBERRY GAS INTRUSION RATES

Site	Cavern #	Date of Oil Fill	Date of Sample	Gas Intrusion psi/year @80°F
West Hackberry	6	Nov-77	Mar-94	0.03
	9	Nov-78	Mar-94	-0.06
	11	Oct-77	Mar-94	-0.05
	102	Sep-83	Jun-93	-0.01
	103	Sep-82	Mar-94	0.02
	104	Oct-82	Mar-94	-0.03
	105	Nov-82	Mar-94	0.04
	106	Nov-85	Mar-94	0.00
	107	Jul-83	Mar-94	-0.05
	108	Jun-83	Mar-94	-0.05
	109	Nov-86	Jun-93	-0.18
	110	Dec-83	Mar-94	-0.07
	111	Mar-87	Mar-94	0.07
	112	Jun-85	Mar-94	-0.04
	113	Jul-84	Mar-94	-0.02
	114	Oct-84	Mar-94	-0.04
	115	Aug-86	Mar-94	-0.09
	116	Mar-85	Jun-93	-0.18
	117	Jul-88	Aug-93	0.10

Table 3

BIG HILL GAS INTRUSION RATES

Site	Cavern #	Date of Oil Fill	Date of Sample	Gas Intrusion psi/year @ 80” F
Big Hill	101	Feb-89	Apr-94	-0.24
	102	Apr-89	Apr-94	-0.13
	103	May-89	Apr-94	0.12
	104	Mar-89	Apr-94	-0.07
	105	act-88	Apr-94	0.25
	106	Mar-89	Apr-94	1.85
	107	Ott-88	Apr-94	.72
	108	Jan-89	Apr-94	1.36
	110	Nov-88	Apr-94	0.25
	111	Apr-90	Apr-93	14.45**
	113	Mar-90	Apr-94	7.27**
	114	Apr-90	Apr-94	8.74**

** small quantity of stored oil exaggerates intrusion rates

Table 4

BAYOU CHOCTAW GAS INTRUSION RATES

Site	Cavern #	Date of Oil Fill	Date of Sample	Gas Intrusion psi/year @80˚F
Bayou Choctaw	15	Jan-78	Feb-94	-0.08
	17	Apr-87	Feb-94	0.14
	18	Dec-78	Feb-94	0.05
	19	Nov-78	Feb-94	-0.07
	20	May-81	Mar-94	0.14
	101	Oct-88	Feb-94	0.22

VI Predicted Future Gas Intrusion Rates

It is our belief that the best estimate of future gas intrusion into an SPR cavern should be based upon its historical intrusion rate information. These historical intrusion measurements have been detailed in the previous section. We have shown further that the gas permeability model provides the most credible explanation for gas inflow into caverns. The release of gas from the salt can account for existing inflows. The variability in cavern gas content can be explained by the inherent variability or inhomogeneity in domal salt properties. This mechanism predicts a decreasing gas intrusion rate with time in SPR caverns. It predicts that the intrusion rate for the second ten years will be approximately one-half of the historical intrusion rate. However, for this study, it is believed that the predicted gas intrusion of approximately half of the historical observed rate is the best engineering estimate for future gas intrusion, subject to continued refinement. The maximum rate is taken to be the average over the historical observation period.

In order to understand the significance of the gas intrusion rates presented in Tables 1, 2, 3, and 4, we have performed a series of flash calculations to relate these rates to future GOR rise rates at several temperatures. These calculations are described in Appendix 7. As a basis for these calculations, it is assumed that stored gassy oil will be degassed to a bubble point of 12.2 psia at 100°F. Under these circumstances if the bubble point of a cavern increases by 0.25 psi per year, then it will require degassing at a ten year interval. Consequently, those caverns having a historical intrusion rate corresponding to 0.25 psi/year should be singled out for further attention. Caverns which come close to fitting this profile are listed in Table 5.

Obviously, Bryan Mound Caverns 2, 101, 103, 109, 111, 112, and 114 dominate with respect to gas intrusion. These specific caverns and Bayou Choctaw 20 and 10 1 should be monitored closely in the future. Measurements from these caverns will allow better estimates for gas intrusion to be established sooner.

The source of the gas in oil at Big Hill has a high degree of uncertainty since gas observed in Caverns 106, 107, and 108 came from the former Sulphur Mines SPR site. Hence, it is impossible to tell clearly how these caverns are performing. Intrusion rates for Big Hill Cavern 111, 113, and 114 seem to be very large; however, these rates may be exaggerated because of the small amount of oil stored in these caverns.

West Hackberry has no caverns with gas in significant quantities, and hence no intrusion is predicted by this data.

Table 5

**Predicted Likely and Maximum
Future Gas Intrusion Rates
for Caverns with Elevated Gas/Oil Ratios**

	Likely Future Gas Intrusion Rate (psi/yr @ 80 °F)	Maximum Future Gas Intrusion Rate (psi/yr @ 80 °F)
Bryan Mound 2	0.18	0.36
101	0.42	0.83
103	0.97	1.94
109	0.31	0.62
111	0.95	1.89
112	1.11	2.22
114	0.29	0.57
Big Hill	Unknown*	Unknown*
Bayou Choctaw 20	0.07	0.14
101	0.11	0.22

*Current oil measurements at Big Hill reflect Sulphur Mines gas intrusion, hence future Big Hill intrusion rates are currently unknown. Likely future intrusion rates equal one-half of measured values; maximum future intrusion rates equal the historically measured intrusion rates.

VII Conclusions

The following conclusions were reached in this study of the gas intrusion into SPR caverns :

- Two mechanisms of gas intrusion were investigated for consistency with known phenomena. These mechanisms were gas release during leaching and gas inflow due to stored gas in the salt. The mechanism of gas release during leaching generally accounts only for very small amounts of gas in the caverns although higher gas contents from this mechanism (up to 1 SCF/BBL) are conceivable. The mechanism of release of gas contained in the salt offers the greater consistency with ‘known phenomena. This permeability inflow mechanism predicts that future rates will be reduced from their historical levels. The accuracy of these predictions should be improved as additional data are obtained.

- No rules or cause and effect relationships other than generalized associations of geologic features with gas in certain caverns can be made. Because the gas is predominantly petrogenic in origin it was prudent to attempt to make such an association.

- A review of historical operating data for five Bryan Mound caverns supports the contention that higher operating pressures will reduce gas intrusion into SPR Bryan Mound caverns.

- **The historical evidence and analyses presented imply that gas will most likely continue to intrude into SPR caverns in the near future.** Considering these measured gas quantities, intrusion rates of gas into SPR caverns have been determined.

- All caverns in the SPR were analyzed for gas content and intrusion rates were determined. Highest intrusion rates were observed at the Bryan Mound site. Lesser quantities of gas appear to be present in caverns at Bayou Choctaw and West Hackberry. At Weeks Island the gas content is much smaller.

VIII Recommendations

Existing areas of concern need to be addressed either through gas removal capability developments for drawdown, or gas removal and restorage. An oil/gas monitoring plan for the future needs to be developed which will assure timely identification of caverns with significant gas intrusion rates. Since oil/gas data is costly and/or difficult to obtain routinely, it is recommended that the caverns identified with potentially high intrusion rates of gas receive greater attention. Of the known gas producing caverns, most of these are at the Bryan Mound site. Monitoring of selected caverns at Big Hill will be necessary to establish a future baseline for gas intrusion. From that baseline, monitoring can be then planned. Bayou Choctaw will require some continuous effort to at least watch Cavern 20 and 10 1. West Hackberry can be occasionally sampled.

As more data becomes available, a plan with much greater detail will be developed. It is recommended that a graded approach be taken such that higher-risk caverns receive proportionately higher attention. New data on an annual basis on the highest gas intrusion caverns appears justifiable, whereas low gas intrusion caverns might be sampled at longer intervals, such as every five years, in conjunction with ongoing periodic sampling.

It is recommended that caverns be operated at or near the maximum operating pressure to minimize future gas intrusion into the stored oil.

Some continuing effort will be carried out with respect to further gas source definition and scenario development. Appendix 6 refers to work to reexamine aspects of Bryan Mound cores. As future gas/oil data is obtained, the theoretical work related to the gas mechanism will necessarily have to be revisited.

IX References

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Appendix 1

Survey of Historical Permeability of Matrix Salt

Sandia National Laboratories

Albuquerque, New Mexico 87185

date: 6/9/93

to: file

from: Stephen J. Bauer

subject: Comments on Permeability values used by B. Ehgartner for study of Transient Gas Flow into an SPR Cavern

The 5 May letter (Ehgartner to Linn: Transient Gas Flow Simulation for a SPR Cavern) made estimates of gas flow into an SPR cavern using a standard transmissivity and storage model. Concern has been raised as to the values used for permeability in the model, **because** these values were from measurements in the field for the WIPP site. The WIPP consists of bedded salt and the SPR consists of domal salt

To put the permeability of salt in perspective the following values for other earthen materials are listed

Material	Permeability (m^2)
Gravel	10^{-7} - 10^{-9}
Sand	10^{-10} - 10^{-12}
Sandstone	10^{-13} - 10^{-16}
Limestone	10^{-17} - 10^{-18}
Granite	10^{-19} - 10^{-22}

A brief literature survey was completed. Permeability measurements for salt are sparse.

Data source	Permeability (m^2)
Bedded Salt	
Values used by Ehgartner (WIPP)	10^{-20} - 10^{-22}
Hutchinson (Reynolds & Gloyna, 1960)	~10^{-17} - 10^{-18}
New Mexico (Sutherland & Cave, 1980)	-5 x 10^{-19}
Domal Salt	
Asse, Germany (Peach, C. J. 1990)	-3 x 10^{-18} -9 x 10^{-21}
Cote Blanche (Golder, 1977)	~10^{-16} - 10^{-18}
Tatum (Wes, 1963)	~10^{-14} - 10^{-16}
Grand Saline (Reynolds & Gloyna, 1960)	~10^{-16}
Avery Island (Blankenship & Stickney, 1983)	-6 x 10^{-15} - 4 x 10^{-18}

The older permeability measurements show greater values for permeability than more recent measurements. My conversations with those who made the measurements suggest that this trend follows the increase in resolution of the instrumentation with time.

The literature (Peach, C. J. 1990) further indicates that the permeability of salt tends to increase as a result of deformation and this has to do with the mechanism of gas flow through the salt. This would mean that the salt permeability in the vicinity of caverns would tend to increase with time, as inward deformation of the caverns is ongoing.

The range used by Ehgartner is on the lower end of the range of values listed for domal salt. Therefore, given the assumptions of the modeling technique, the times predicted for gas intrusion into the caverns are reasonable.

copy to:

6113 J. Linn
6113 B. Ehgartner
6113 T. Hinkebein
6113 J. Todd

Appendix 2

Permeability Changes in Salt Surrounding SPR Caverns

Sandia National laboratories

Albuquerque, New Mexico 87185

date. July 14, 1993

to: J.K. Linn, 6113

Brian T Ehgartner

from: B.L. Ehgartner, 6113

subject: Permeability Changes in Salt Surrounding SPR Caverns

One of the assumptions used in modeling the gas inflow into SPR caverns was a constant permeability, both temporally and spatially. Yet the creation of a cavern field induces stress changes on the hosting salt. Under certain stress states, microfractures can form and dilate resulting in a significant increase in permeability.

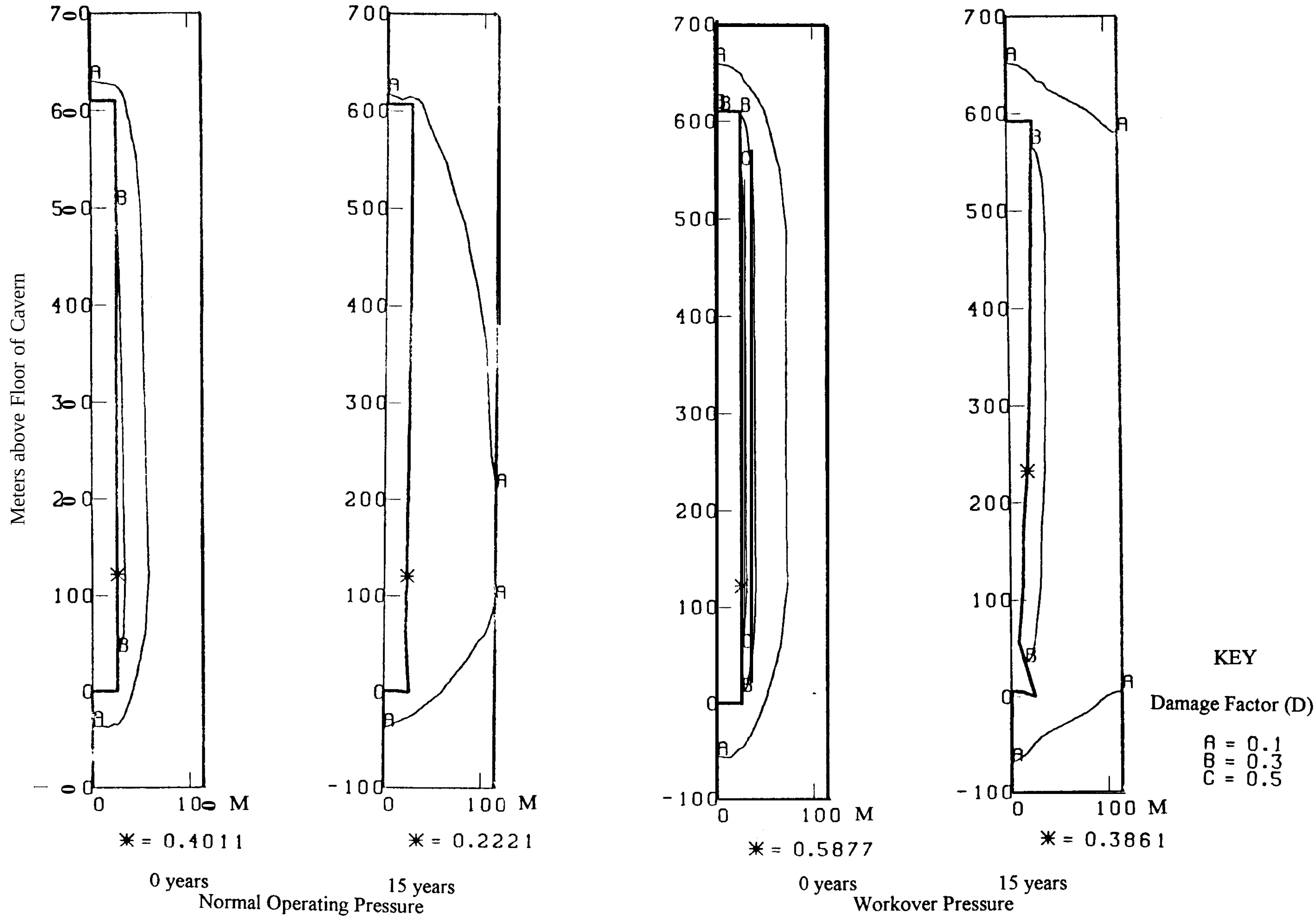
The potential for dilatant behavior was examined through a series of finite-element creep analyses that predicted the stress state around a cavern field and 'postprocessed' the results using a dilatancy criteria (Sambeek, Ratigan, and Hansen, 1993). The dilatacy criteria is defined by the first invariant of the stress tensor and the second invariant of the deviatoric stress tensor, based on the review of three laboratory testing programs on WIPP, Avery Island, and Asse salt. Since the detection of dilatancy is limited by the ability to measure increases in sample volume during the creep and quasi-static tests performed on the salt core, the criteria is used here to delineate potentially significant changes in permeability. A typical SPR cavern field was simulated (for details see Ehgartner, 1992) at 1) normal operating pressure and 2) under workover conditions where the wellhead pressure on the oil side was reduced to atmospheric.

The results of the analyses predict no dilatant behavior of the salt surrounding SPR caverns regardless of the cavern pressure evaluated. The predicted damage factor is contoured in the attached Figure at the start of the simulations and 15 years later. A damage factor (D) equal to or greater than 1 indicates dilatant behavior. No dilatancy is predicted by the criteria for damage factors less than one. The highest damage factor of 0.59 was predicted for the cavern immediately following the workover. A considerable improvement was noticed in the damage factor when operating at normal pressure (D= 0.40).

The above analyses suggest that salt is not measurably dilated due to stress perturbations that result from creating and operating a SPR cavern field. It follows that without dilation of the salt, deformation will occur through isovolumetric creep and significant increases in permeability are unlikely.

Ehgartner, B.L., "Effects of Cavern Spacing and Pressure on Subsidence and Storage Losses for the US Strategic Petroleum Reserve," SAND91-2575, Sandia National Laboratories, Albuquerque, NM, March 1992.

Van Sambeek, L.L, J.L. Ratigan, and F.D. Hansen, "Dilatancy on Rock Salt in Laboratory Tests," 34th U.S. Rock Mechanics Symposium, Madison, WI, June 1993.



Predicted Damage Factors for SPR Cavern Fields Operated Under Normal and Workover Pressures. A Damage Factor Less Than One Implies No Measurable Dilatancy.

Appendix 3

Matrix Salt Radial Flow Permeability Model

Sandia National laboratories
Albuquerque, New Mexico 87185

date May 5, 1993

to: J.K. Linn, 6113

Brian Ehgartner

from Brian Ehgartner, 6113

subject Transient Gas Flow Simulation for a SPR Cavern

The finite-difference method was used to solve the following equation for unsteady gas flow into a SPR cavern.

$$\frac{\delta^2 h}{\delta r^2} + \frac{1}{r}\frac{\delta h}{\delta r} = \frac{S}{T}\frac{\delta h}{\delta t}$$

This equation was approximated explicitly in finite-difference form as:

$$h_i^{n+1} = [(h_{i+1}^n - 2h_i^n + h_{i-1}^n)rTdt/dr + h_i^n(Srdr - Tdt)] / (Srdr - Tdt)$$

where h is head at a particular node i and time step n, dt is the time step, dr is the nodal spacing along radius r, S is the storage coefficient, and T is the transmissivity of a confined aquifer.

The above expression formed the basis of a finite-difference code. The code was verified by comparing the predicted piezometric surfaces at various times to a text book example problem of a reservoir drawdown (Wang and Anderson, 1982).

For the SPR cavern simulation, the parameters of Table 1 were used.

Table 1
Parameters

Permeability	1E-21 m^2
Gravity	9.81 m/s2
Viscosity	0.024 cp
Density	.084 g/cm^3
Porosity	0.01
Compressibility of gas	0.1015 MPa^{-1}

The model geometry consisted of a 2000 ft. high cavern with a radius of 100 ft. completely filled with oil. The cavern roof was at 2500 ft. below surface. The outer flow boundary (gas reservoir) was placed 130 ft. (40 m) from the cavern wall. This distance corresponds to the closest SPR cavern to the edge of the a dome (Bayou Choctaw 20). A constant oil pressure of 1970 psi was applied to the cavern wall. This pressure is based on the mid-height of the cavern at 3500 ft. deep and a brine/oil interface at 4500 ft. assuming a brine gradient of 0.52 psi/ft and oil gradient of 0.37 psi/ft. The lithostatic and hence pore pressure at this depth was assumed to be 3392 psi based on 2000 ft. of overburden at 1 psi/ft and salt at 0.928 psi/ft. Flow was confined to the radial direction with planar flow boundaries at the top and bottom of the cavern.

The result are shown in Figures 1 and 2. Figure 1 shows the piezometric surface for various times. The piezometric surface does not connect to the outer model boundary until 32 years. Thus the flow generated up to that time is solely from storage releases from the salt pores due to decreases in the piezometric surface. Once flow starts to occur across the salt (from the gas reservoir into the cavern), the flow rate does not notably increases. The predicted flow is shown in Figure 2. The predicted quantities at 10 years fall within the range of those measured in the field, suggesting storage releases from surrounding salt as a credible mechanism for explaining the gas in SPR caverns.

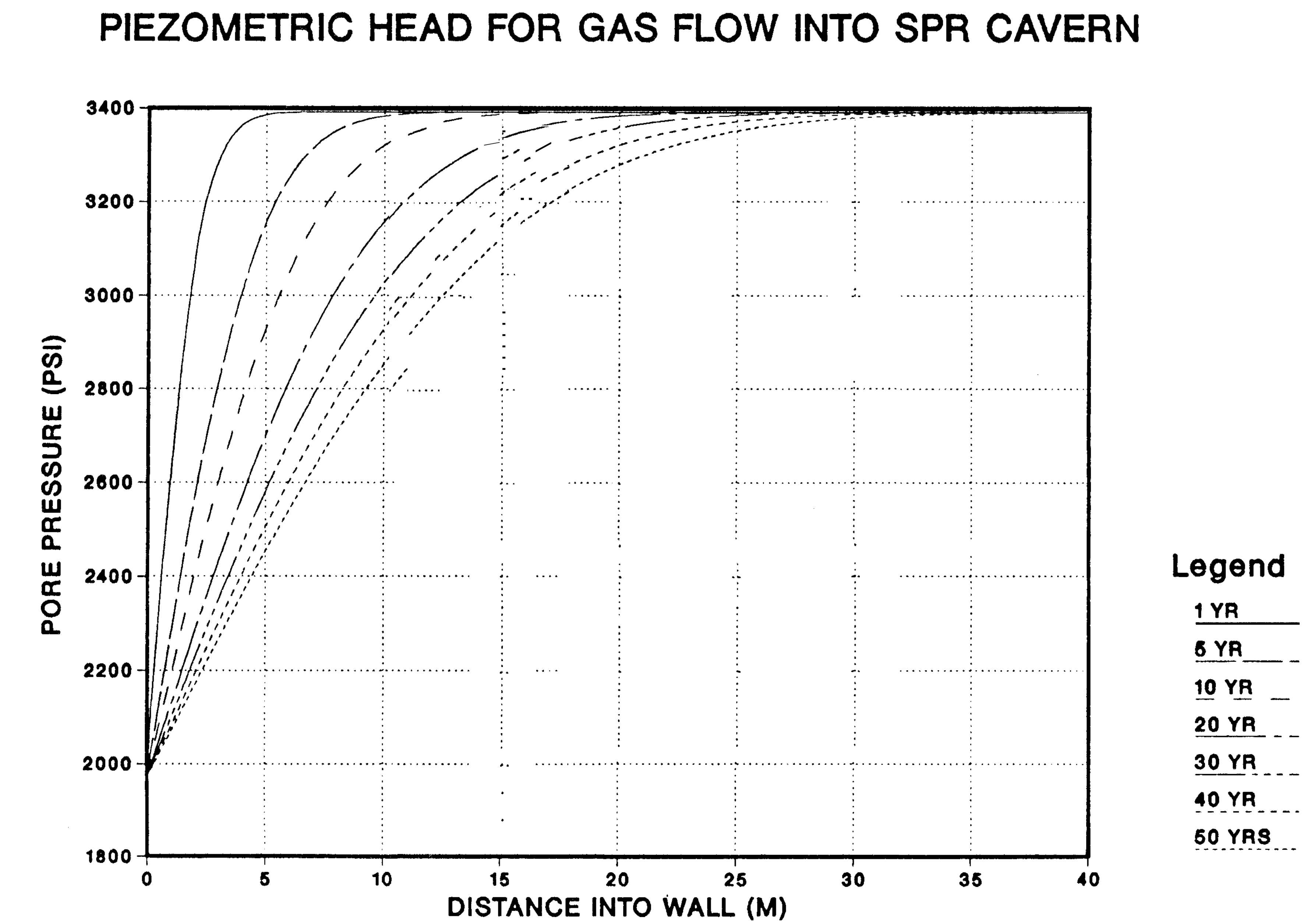
Several additional figures are attached that show the sensitivity of the results to changes in depth, operating pressure, and permeability. Depths of 2500, 3500, and 4500 ft. were evaluated. Well head pressures on the oil side of 0, 338, and 675 psi were evaluated. Permeabilities of 1.0E-20, 1.0E-21, and 1.0 E-22 m^2 were evaluated. The base case as defined in the original calculation was at 3500 ft. (the average cavern depth), with a well head pressure of 675 psi (oil/brine interface at 4500 ft.), and a permeability of 1.0E-21 m^2 (typical of WIPP salt).

Flow is linearly proportional to depth, hence the average depth of 3500 ft. used in the original calculation is appropriate for estimating flow into a cavern emplaced at 2500 to 4500 ft. Similarly, flow is linearly proportional to the cavern operating pressure. These results show that flow is a linear function of the driving pressure-- the difference between lithostatic pressure at the outer model boundary and the cavern pressure. In contrast, orders of magnitude change in permeability results in flow changes on the order of a factor of approximately 3.5.

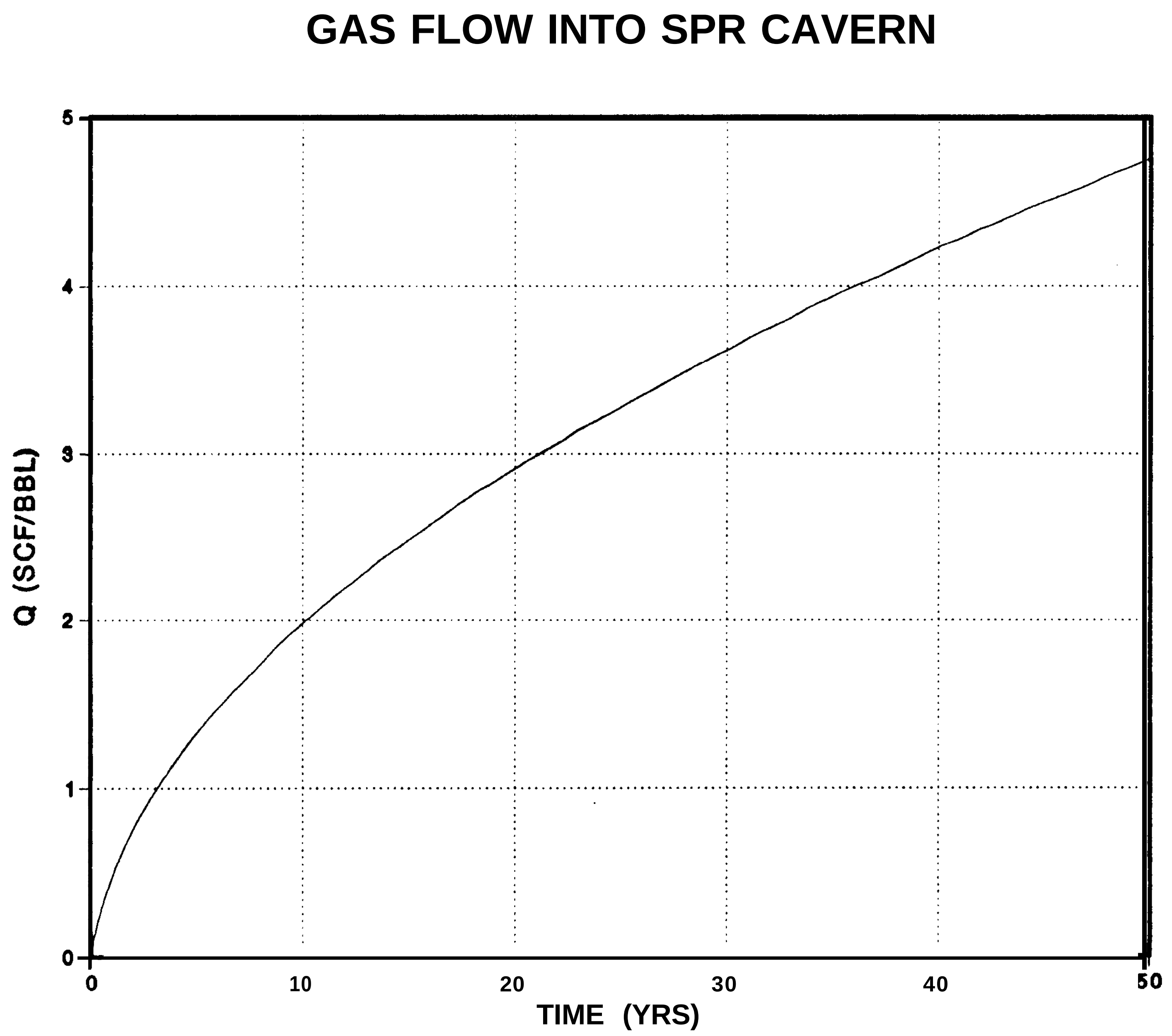
The results of the above modeling are encouraging as they suggest that the measured gas quantities in SPR caverns can be attributed to storage releases from the salt immediately surrounding a cavern and that connection to a nearby gas reservoir does not notably change the inflow. However, the results of this model should not be used to make design or programmatic decisions as the treatment of gas as a compressible is incomplete. At this point, it may be prudent to use a more sophisticated flow model that better simulates the dynamics of gas flow.

ref. Wang, F.H. and M.P. Anderson, Introduction to Groundwater Modeling, Freeman and Co., San Francisco, 1982.

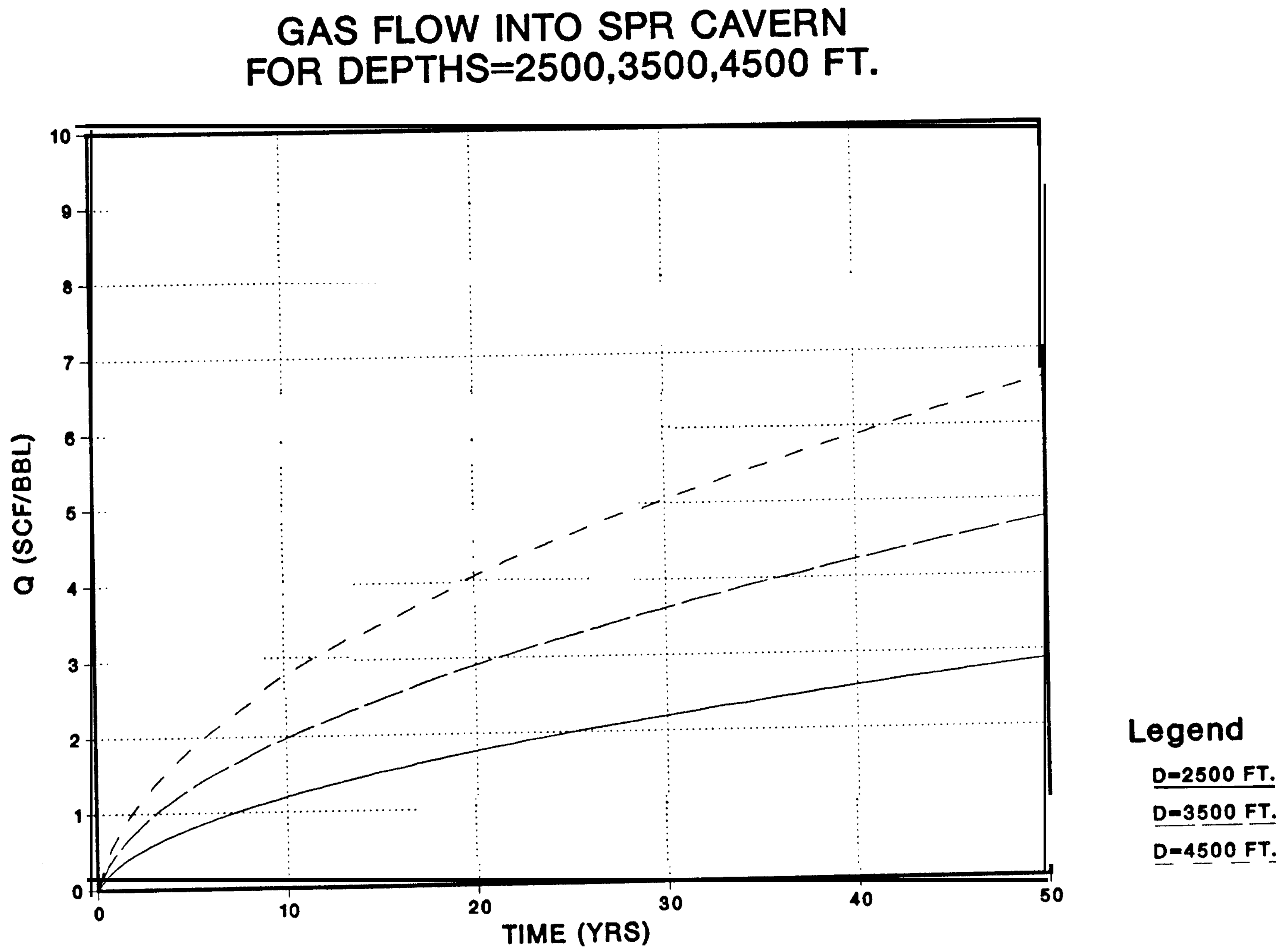
FIGURE 1


PIEZOMETRIC HEAD FOR GAS FLOW INTO SPR CAVERN
PORE PRESSURE (PSI)
3400
3200
3000
2800
2600
2400
2200
2000
1800
0
5
10
15
20
25
30
35
40
DISTANCE INTO WALL (M)
Legend
1 YR
5 YR
10 YR
20 YR
30 YR
40 YR
50 YRS

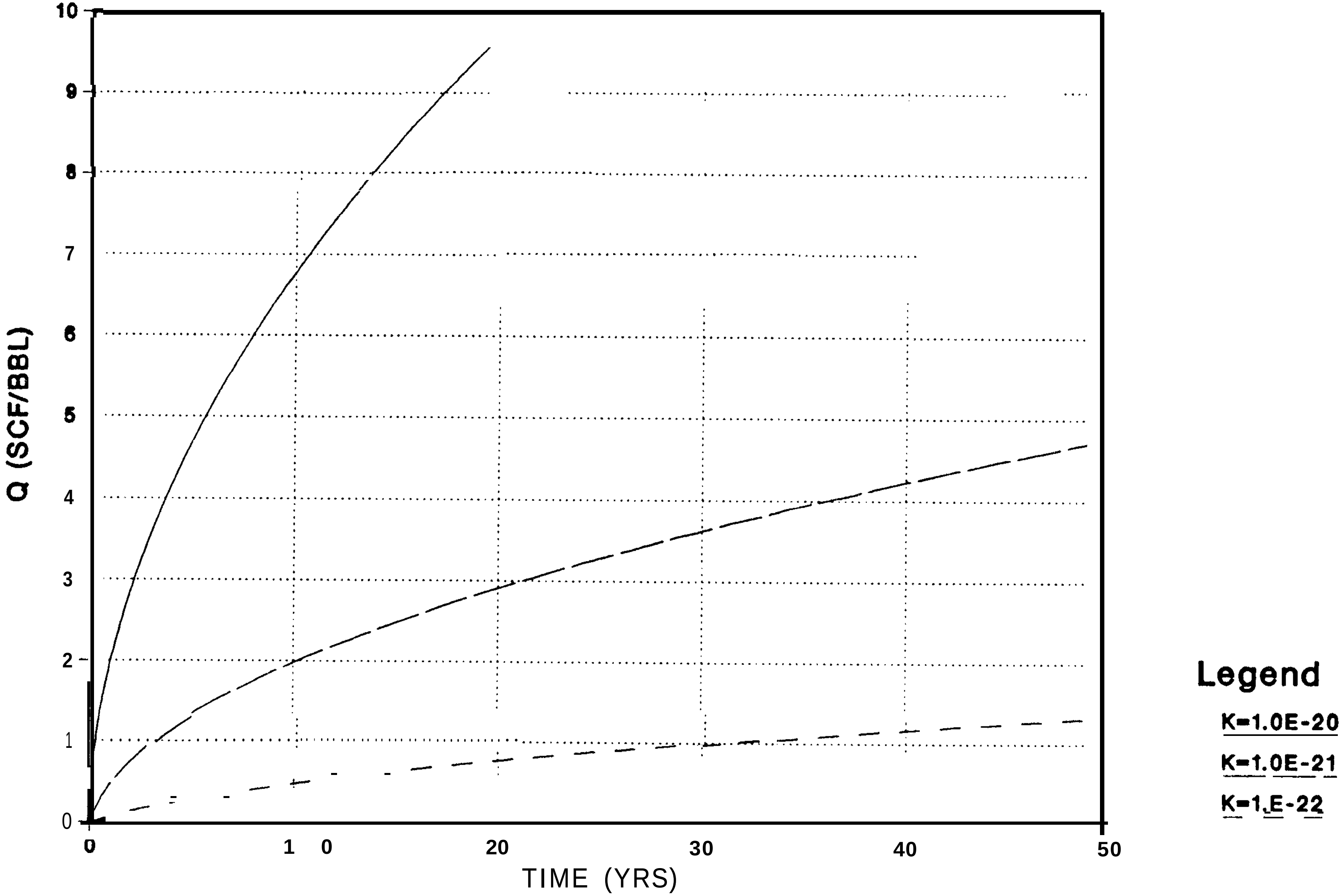
Corrected Figure 2.



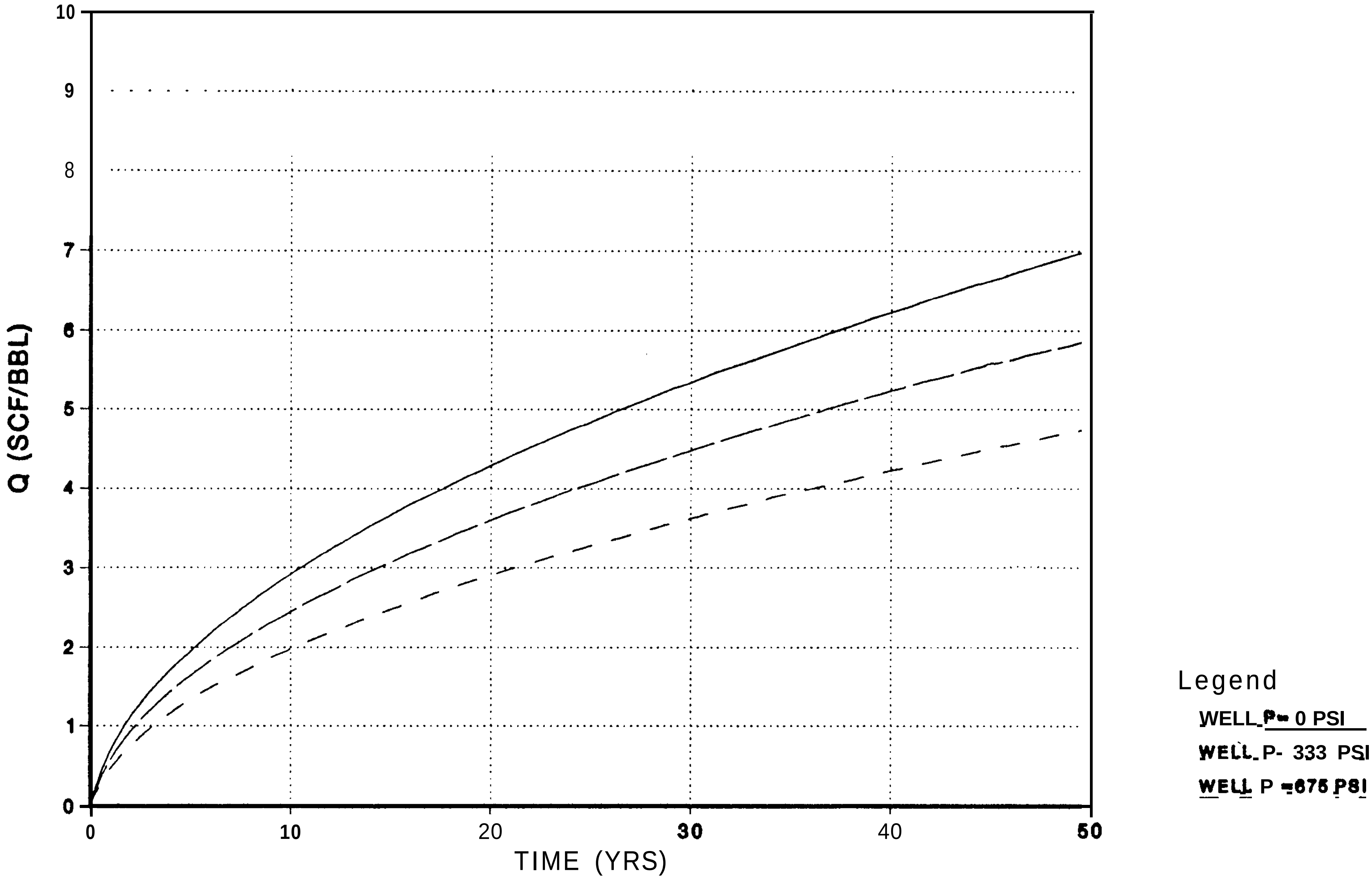
Additional Figures Showing Results of Sensitivity Study


GAS FLOW INTO SPR CAVERN
FOR DEPTHS=2500,3500,4500 FT.
Q (SCF/BBL)
0
1
2
3
4
5
6
7
8
9
10
0
10
20
30
40
50
TIME (YRS)
Legend
D=2500 FT.
D=3500 FT.
D=4500 FT.

GAS FLOW INTO SPR CAVERN FOR K=E-20,E-21,E-22 M**2



GAS FLOW INTO SPR CAVERN
FOR OIL PRES=0,338,675 PSI



Appendix 4

Lifetime Average Operating Pressure versus Gas Content -- Bryan Mound Caverns

Sandia National laboratories

Albuquerque, New Mexico 87185

date: July 16, 1993

to: Tom Hinkebein 6 113

from: Jim Todd 6113

subject: Lifetime Average Operating Pressure versus Gas Content -- Bryan Mound Caverns

As you are aware, we have been looking at the possibility of finding a correlation between the average lifetime operating pressure of caverns at Bryan Mound and the measured gas content of the oil stored in the respective caverns. It is postulated that more gas should be produced at lower operating pressures. Consequently, the observed gas content should be higher for similar caverns that are operated at lower average pressure. The significance of such a conclusion may be: 1) inference as to the source and possible depletion rate of the gas reserve, and 2) justification for operating the caverns at maximum operating pressure to minimize gas intrusion.

There are many factors that can affect the gas production rate and gas content of the stored oil, most of which can not be practically determined. Some of these are listed below for reference and discussion.

1. Type of Gas Reservoir -- The speculation as to the source of gas, i.e., the reservoir, has included: a) gas distributed throughout the salt interstices, b) isolated "pockets of gas in high porosity salt, c) reservoirs external to the dome flanks, and d) deep gas pockets.

2. Path of Gas from Reservoir to the Cavern -- Again by speculation, there are several possible mechanisms by which the gas, driven by a pressure gradient, can move from the reservoir to the cavern. The first is by flow or diffusion through undisturbed salt. A second is through an anomalous zone (shale stringer, fault, etc.) which intersects the cavern or is located near the cavern wall. Also possible is a one-time event where the cavern directly connects to the reservoir during leaching of the salt cavern walls. This could produce an outburst of gas into the oil or brine.

3. Cavern Operating Pressure -- The percentage change in cavern pressure at depth due to changes of wellhead oil side operating pressure is of the order of 10 percent. At a cavern depth of 3000 A (a nominal midpoint depth for Phase II and III caverns), there is a 1,110 psi hydrostatic head due to the oil. Adding a typical oil side wellhead pressure of 600 psi yields a total of 1,710 psi at depth. The difference between this pressure and lithostatic pressure is the driving pressure that causes gas flow into the cavern. For this example, a 200 psi decrease in the surface pressure would cause a 15 percent increase in the driving pressure at a depth of 3000 ft. At a 5000 ft depth, the change would be about 8 percent.

4. Depth of Reservoir -- We would expect reservoir gas pressure to be higher for deeper reservoirs. This suggests that the gas buildup rate in caverns connected to deep reservoirs should be less sensitive to changes in cavern surface operating pressure than would caverns connected to shallow reservoirs.

5. Mean Cavern Depth -- We know of no practical way of directly determining either the depth of the gas reservoir or the point(s) at which the gas is entering the cavern. Therefore we generally use the cavern mean depth for calculating pressures and for normalizing data obtained from caverns that have substantially different heights and/or depths.

6. Date(s) of Oil Fill -- If we assume a somewhat constant gas intrusion rate, is reasonable to normalize gas content to the total time that the oil has been in the cavern. It is useful when comparing caverns to normalize the gas content in units standard cubic feet of gas per barrel of oil per year.

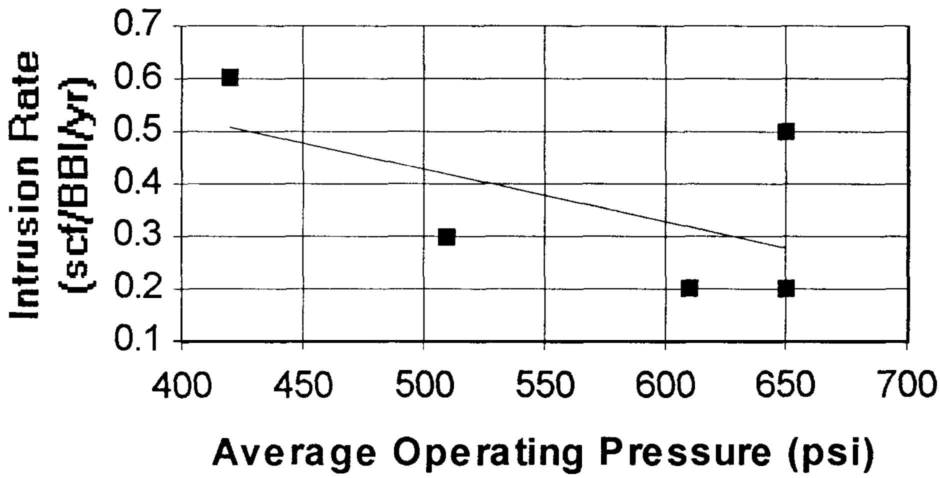
In Table I, we list the nominal date of fill, the mean cavern depth, the average cavern operating pressure since fill, the measured gas content (1993 data), and the calculated yearly average gas intrusion rate for five Bryan Mound caverns. Caverns 2, 101, 110, and 112 were selected because of the ready availability of data at Sandia. Cavern 103, data for which was compiled by DynMcDermott, was selected to more completely cover the range of measured gas content. The reported gas contents are the most recent generally accepted values as provided by you. We have concluded that the Average Intrusion Rate, calculated by dividing the current Measured Gas Content by the number of years from the Nominal Fill Date, is an appropriate way to normalize gas content so that caverns can be directly compared.

TABLE I

CAVERN	NOMINAL FILL DATE	MEAN CAVERN DEPTH (ft)	AVERAGE. OPERATING PRESSURE (psi)	MEASURED GAS CONTENT (scf/BBl)	AVERAGE INTRUSION RATE (scf/BBl/yr)
2	6/80	1560	420	7.6	0.6
101	1/85	3090	610	2.8	0.2
103	12/84	3040	650	4.2	0.5
110	6/83	3140	650	2.0	0.2
112	6/84	3160	510	3.0	0.3

Figure 1, presents a plot of Average Intrusion Rate versus Average Operating Pressure. With these five caverns, there appears to be a general trend, as indicated by the regression line, to support the hypothesis that higher operating pressures reduce gas production. There is large scatter in these data which suggests that there are other factors that significantly affect gas production rate. Although it may be worthwhile to try to refine these data and include other Bryan Mound caverns, we suspect that the unknown factors will continue to cause significant uncertainties.

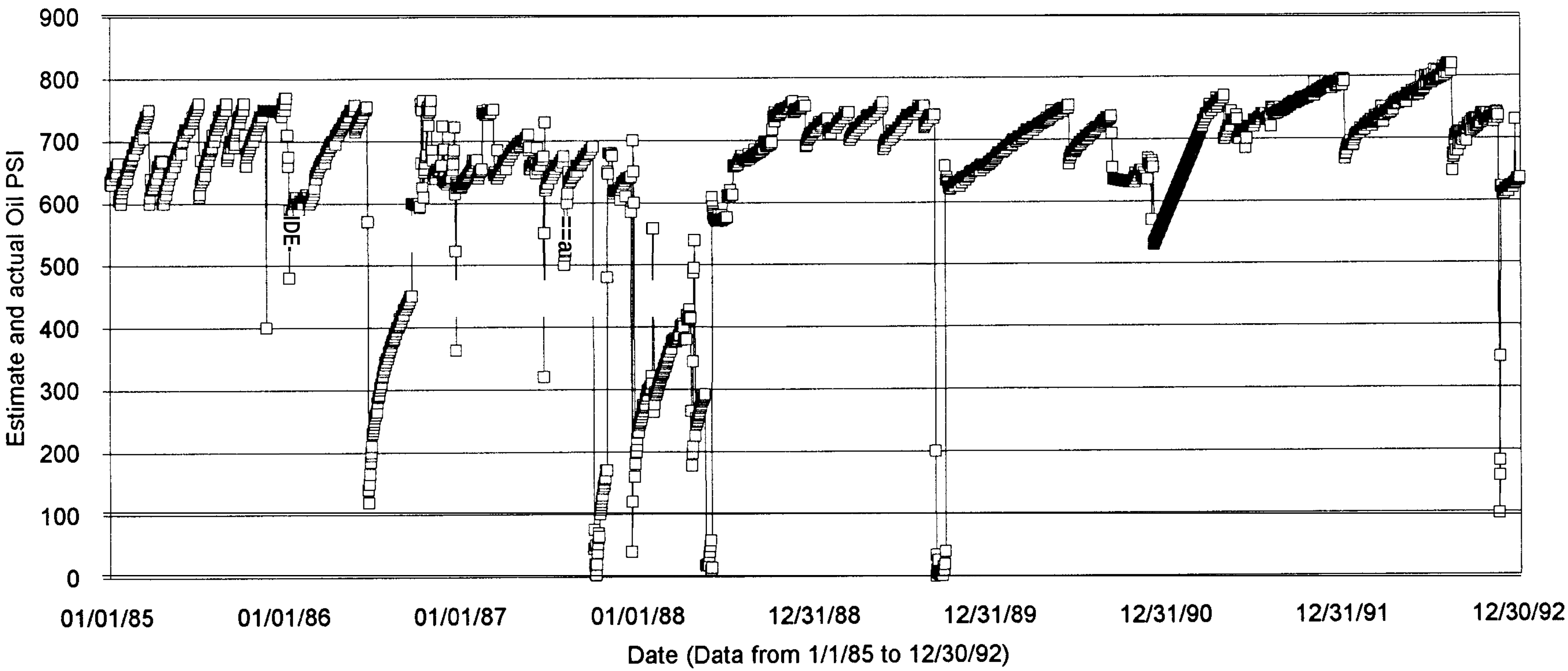
FIGURE 1 -- Gas Intrusion Rate



In summary, we conclude that this review of historical operating data for five Bryan Mound caverns supports the contention that higher operating pressures will reduce gas intrusion into SPR Bryan Mound caverns. Although more detailed evaluation of these and other Bryan Mound caverns may increase our understanding this phenomena, there is substantial evidence that other factors will continue to be significant and cause unresolvable uncertainties in the data.

copy:
J. K. Linn 6113
J. L. Todd 6113
Staff 6113

Bryan Mound Cavern 103
DynMcDermott Data



Appendix 5

The Impacts of Gas Intrusion and Geothermal Heating on Crude Oil Stockpiled in the U. S. Strategic Petroleum Reserve

Solution Mining Research Institute, Fall Meeting
Hannover, Germany, September 25 - October 1, 1994

The Impacts of Gas Intrusion and Geothermal Heating on Crude Oil Stockpiled in the U.S. Strategic Petroleum Reserve

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Abstract-In 1992, the Strategic Petroleum Reserve (SPK) began investigating the impacts of two natural phenomena on the drawdown and distribution of stockpiled crude oil. One phenomenon is geothermal heating of the crude oil due to the natural temperature gradient of the Earth. This heating of the oil increases its true vapor pressure which could adversely impact the level of atmospheric emissions at delivery. The second phenomenon is intrusion of natural gases from the domal salt into the stored crude oil. Natural gas commonly occurs in domal salt of the Gulf Coast region and has been the subject of considerable study by the U.S. Bureau of Mines and others. While intrusion rates are small, the gas that has built up during the 16 years since storage in the SPK began has resulted in an increase in the oil's vapor pressure. Salting out of atmospheric gases from the water used to leach caverns could be contributing to the increased vapor pressure observed. This increase in vapor pressure could result in atmospheric emissions that exceed environmental and safe operational limits during drawdown. Studies to determine the extent and magnitude of geothermal heating and gas intrusion are nearly complete. The quality of the crude oil is unaffected, except for an increase in vapor pressure caused by the elevated temperature and the presence of gases, With cooling and gas removal, applying existing technology, the crude oil can be transported and relined without presenting environmental or safety problems.

INTRODUCTION

Methane and Other Gases in Domal Salt

The natural occurrence of methane and other light hydrocarbons in domal salt of the U.S. Gulf Coast has been recognized for a number of years. The U.S. Bureau of Mines (BoM) has conducted studies to determine the methane content of domal salt, because of its explosive potential and impact on mining operations [1][1]. These studies indicate that the gas content is generally in the range of 0.0003 to 7.4 mL per 100 g salt (≈0.0001 to 1 .O ft^3 per barrel), The presence of higher hydrocarbons was reported by the BoM to be significant in some cases. No quantitative data were presented on the amounts of these higher hydrocarbons, but ethane through pentane were reported to be present in some samples. Various other gases including nitrogen, hydrogen, and hydrogen sulfide have also been reported to occur in salt, but little or no quantitative data are available **[2]**.

Based on analyses of 15 salt samples from four Gulf Coast domes done for the SPR, methane comprised greater than 95 percent of the hydrocarbons present in 14 of the samples **[3]**. In the one exception, methane comprised approximately 8 1 percent; with ethane, propane, *iso-* and N-butane, and *iso-* and *n*-pentane all present in minor amounts. The gas content of these samples ranged from 0.4 to 7.6 mL per 100 g salt (-0.04 to 1 .O ft^3 per barrel), in good agreement with the BoM data.

More recently, further analyses of the gas content of salt were made on random samples of the cores recovered from several of the wells drilled at Bryan Mound, TX, in the 1970s during development of the SPR. In all cases, the methane content was less than 0.007 mL per 100 g salt **[4]**. From the BoM studies, the nature of domal salt is such that zones of "gassy" salt could be missed in a random sampling such as undertaken in this latter study. Besides, 15 years had elapsed between the time these cores were drilled and the samples collected and analyzed, and much of the occluded gases could have escaped.

Although the above values for gas in salt are seemingly small, gas outbursts of more than 17,000 m^3 (600,000 A") of methane have occurred in U.S. Gulf Coast salt mines **[5]**. Moreover, continuous methane outgassing from a zone of anomalous salt was measured in one mine over a period of 47 days, and reported in another BoM study **[6]**. Flow rates of as high as 2,500 m^3 (88,000 ft^3) per day were measured during this study.

During leaching of one of the caverns at Big Hill, TX, a significant quantity of "wet" gas was encountered. More than 15 m^3 (90 barrels) of liquid condensate was recovered in a few days and an

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'Bold numbers in brackets designate references.

unknown volume of gas vented and flared. Methane comprised approximately 80 percent of the gas. Although this incident apparently resulted from leaching of an isolated pocket of gassy salt, this cavern is one of the most gassy in the entire SPR, based on operating history and tests to be discussed later.

From these studies, it is reasonable to expect that methane and other light hydrocarbons will be released from the salt during leaching of the caverns and dissolve in stored oil, although the amount of light hydrocarbons accompanying the methane is difficult if not impossible to quantify. On the basis of one sample, it appears that up to 20 percent of the salt-occluded gases entering a cavern could consist of hydrocarbons other than methane. Quantities will vary, depending on the nature of the salt, but could be as high as 200 mL per m^3 (1.1 ft^3 per barrel). Zones of anomalous salt intersecting the cavern interval could result in even greater quantities of gas building up in stored oil.

Other Sources of Gas

Substantial quantities of the atmospheric gases nitrogen and oxygen would have come out of solution from the surface water used to leach caverns because of the "salting-out" effect **[7,8]**, and could have dissolved in stored oil. Based on solubility data for fresh water, approximately 75 L per m^3 (0.4 ft^3 per barrel) of nitrogen and 35 L per m^3 (0.2 ft^3 per barrel) of oxygen could have been released during the leaching of a ten million barrel cavern. Actual quantities that built up would be lower because some of these atmospheric gases would have been carried out of the cavern with the brine. The reactivity of oxygen with oil components such as sulfur compounds and iron is so great, however, that it would be virtually depleted within a short period **[9,10]**. Only traces of oxygen have been detected in gas separated from SPR crude oil, as discussed later. Nitrogen quantities, on the other hand, are relatively substantial in some caverns and exceed the quantity of methane in many cases. The amount of nitrogen present is important, because its affect on vapor pressure is approximately five times greater than that of methane. During operational exercises, injections of "air''-saturated surface water will result in further atmospheric gases becoming dissolved in the stored crude oil. Generally, these incremental quantities are small in relation to the quantity that salted-out during cavern development.

At the now abandoned Sulphur Mines, LA SPR storage facility, a nitrogen cap was used for many years to prevent crude oil escaping through a leak in the well of one cavern (No. 2-4-5). Over the years during which this gas cap was maintained, a considerable amount of nitrogen could have become dissolved in the stored crude oil.

The amount of nitrogen that has been found cannot be accounted for by loss of this gas during integrity testing of caverns. In most cases, only relatively small incremental volumes of nitrogen are added once the test has been started. Also, during these tests, which typically last only 30 days, the gas/oil interfacial area is less than about 10 m^2 [11]. These conditions would not result in large quantities of nitrogen dissolving in the crude oil.

Geothermal Heating of Crude Oil

Due to the natural geothermal gradient of the Earth, temperature increases with increasing depth. In the Gulf Coast region of the United States, this gradient varies from about 2 to 4°C per 100 m (12 to 20°F per 1,000 feet) of depth [12], with the gradient in salt domes being somewhat higher than in enclosing sediments. On average, geothermal gradient for the salt domes in which SPR caverns are developed is approximately 3.0 to 3.6°C per 100 m (16 to 20°F per 1,000 feet). On this basis, considering the average surface temperature of 23°C (74°F), the maximum temperature that could be expected at equilibrium in the salt is 68°C (155 “F). With convective mixing known to take place in stored oil [13], the temperature is not likely to exceed 57°C (135°F). Nevertheless, even at this temperature, the true vapor pressure (TVP) of some crude oil at the time of drawdown and delivery will exceed what is allowable. The presence of gases such as methane and nitrogen will increase TVP even further.

On average, crude oil received by the SPR has a temperature in the range 21 to 32°C (70 to 90°F), and temperature of oil in some caverns is now nearing 54°C (130°F). This suggests that temperature of the stored oil has been increasing at a rate of approximately 1.1 to 1.7°C (2 to 3 “F) per year. This rate is not constant and should decrease as temperature of the stored crude oil approaches equilibrium with the salt.

GAS CONTAMINATION WITHIN SPR CAVERNS

It has been known for years that natural gas is intruding into some caverns at Bayou Choctaw, Big Hill, and Bryan Mound. Moreover, at the Sulphur Mines site where a nitrogen cap was used, some of this gas could have dissolved in the crude oil. Although studies were started in 1985 to assess the magnitude of the problem at Sulphur Mines, the sampling and analysis technique used was inappropriate for obtaining representative samples and equilibrium gas-in-oil data, respectively. In 1990, more reliable data were obtained, and these showed that the crude oil in cavern 2-4-5 contained anomalously large quantities of both methane and nitrogen. In assessing these data, it was decided that by commingling the Sulphur Mines crude oil with oil from West Hackberry during a drawdown there should be no problem in handling the oil at terminals or aboard tankers. Subsequently, the Sulphur Mines site was sold and its crude oil inventory transferred to caverns at Big Hill, TX. When the crude oil stored at Sulphur Mines was transferred to Big Hill, all oil movements were confined to pipelines with line pressures on the order of 50 psi. This pressure was sufficiently high so that dissolved gases such as nitrogen and methane would have remained in solution during transfer.

In 1992, the operators of a terminal being constructed for distribution of crude oil during a drawdown of the SPR, indicated that TVP of the crude oil at Big Hill was too high for it to be handled in their tanks. The operators stated that the vapor recovery system used on their tanks did not have the capacity to handle the quantity of gas that was contributing to the high TVP, and emissions would exceed permitted levels. Because of this concern, a multidisciplinary committee was formed in late-1992 to study the extent and magnitude of gas contamination in SPR caverns and develop ways to mitigate the problem.

Assessment of Problem

Calculations based on data for the crude oil at Big Hill indicated that the gas content and TVP cannot practicably be reduced to acceptable levels by blending with stabilized crude oil typical of what has been received into the SPR. Calculated blend ratios range from 10: 1 to 19: 1. Knowing that other caverns contained gassy oil, an initially limited assessment of the extent and magnitude of gassy oil in SPR caverns was made. This assessment involved sampling and laboratory measurements of the

P-V-T relationships of oil from each cavern. To validate the results of these laboratory analyses, a pilot plant scale (75-100 barrels per day) gas separation test (Figure 1) was conducted for 12 caverns selected to cover the range of gassy conditions indicated by the laboratory studies. The TVP results from the pilot plant tests were lower in all cases which prompted additional study, ultimately resulting in every cavern in the SPR being tested. Sampling for the pilot plant testing was done directly at the wellhead, either from a moving stream after the casing had been cleared or downhole using a coiled-tubing workover unit. Downhole coiled-tubing sampling was deemed necessary to determine if gas contamination was confined to the roof area of caverns or was uniform throughout. It was believed that gassy crude oil might accumulate in the roof area of caverns due to its relatively lower density. If this were the case, wellhead sampling and pilot plant analyses in which only 10,000 to 20,000 barrels of oil were moved would not be representative of the cavern as a whole. In each of the caverns sampled using the coiled-tubing unit, methane and nitrogen concentrations were more or less uniform throughout.

Recently, validation of the pilot plant scale gas separator has been conducted using a newly available on-stream, true vapor pressure analyzer (TVP-1000) developed by ARCO Exploration and Production Technology for use on the North Slope, Alaska crude oil transportation system. Preliminary results from this series of tests involving four caverns at Bryan Mound, TX, indicate that the crude oil sampled has a lower true vapor pressure or bubble point than indicated by the pilot plant separator. Generally, TVP-1000 results were 10 to 20 percent lower than those of the pilot plant. Further studies are necessary to accurately establish the TVP prior to undertaking degassing the crude oil inventory within individual SPR caverns.

RESULTS

At Weeks Island mine, there is no apparent problem due to presence of anomalous quantities of methane or nitrogen in the stored oil, despite the known presence of gases occluded in the salt. Weeks Island is a conventional mine and is operated at near atmospheric pressure. Gases escaping the salt apparently migrate to the vapor space existing above the stored crude oil, and are drawn off when the mine operating pressure is periodically adjusted.

Natural gas intrusion from salt into some caverns at Bryan Mound, Big Hill, West Hackberry, and Bayou Choctaw, and/or nitrogen buildup resulting from salting-out of atmospheric gases has resulted in some crude oil stored at these sites having a TVP that exceeds the allowable. The bubble point (BP) or saturation pressure of these affected stocks is greater than atmospheric pressure at ambient surface conditions and their gas-oil ratios (GOR) are believed to be unacceptably high from the standpoint of terminal operators. Based on pilot plant results, the present weighted average BP for the entire SPR inventory is 18.6 psia, with a range of 12 to 62 psia. The GOR presently averages 2.6 standard cubic feet (SCF) per barrel, with a range of 0 to 1 I .6 SCF per barrel. Methane content varies from 0.01 to 1.83 mole percent, and nitrogen content varies from 0.01 to 0.26 mole percent. The average of each of these gases is only approximately 0.10 mole percent.

In oil field operations, produced crude oils leaving low pressure gas separators and going into atmospheric storage tanks typically have a BP of 25- 100 psia and a GOR of 30-100 SCF per barrel, in comparison. Although the BP and GOR of SPR crude oils are lower, environmental and safe operating limits are likely to be exceeded, especially during a full-scale drawdown of the reserve. Despite the presence of gases, a test at one SPR site demonstrated that crude oil having a BP of 25 psia can be pumped into floating roof tanks at design drawdown rates. Although atmospheric emissions during this test apparently exceeded permitted levels, no problems were observed in operation of the tank. Of particular concern with respect to safety is the H_2S content of the emissions from certain crude oil streams. In the pilot plant tests, up to 2.5 mole percent H_2S was present in some overhead gas streams.

SOURCE OF METHANE

Based on BoM and other data, the gas content of Gulf Coast domal salt appears too low to account for the quantity of methane present in some SPR caverns, which raises two questions about the source of the gas. First, does any of the methane result from biological activity? Second, could methane be continuously seeping into caverns from the salt stock. These two questions have far reaching implications for the method and schedule of gas removal, and the continued use of some solution-mined caverns for long-term storage of petroleum.

Biogenic vs. Petroaenic Origin

Methanogenic bacteria are known to have degraded fuel oil stocks in caverns in Sweden, and to have generated large volumes of methane in the process [14]. Swedish reserves are, however, in caverns in granite and gneiss with a nearly continuous inflow of relatively freshwater, and the fuel oil stocks are heated to maintain their pumpability. These conditions are conducive to microbial activity. In contrast, the hypersaline environment in SPR caverns is not conducive to bacterial activity [15]. Considerable study has been devoted to this issue and, despite the presence of viable bacteria, there is no evidence to support microbial degradation of crude oil stocks. The most compelling evidence for a petrogenic origin of the methane found in SPR caverns are its $\delta\,^{13}C$ and δ D stable isotope ratios (Figure 2) [16]. In nearly all cases, the methane is clearly of petrogenic and not biogenic origin. Data for two samples, however, suggest a biogenic origin for the methane. These latter two samples were collected from the sludge existing just above the oil/brine interface in a cavern. Biogenic gas is known to exist in certain Gulf Coast reservoirs [17), and it is conceivable that some gas occluded in the salt is of ancient biological origin having been trapped during formation of the domes. Unfortunately, there is no practicable way to distinguish between ancient and modern gases [18]. The presence of relatively large amounts of SO_4^{--} in SPR cavern brines is also believed to be an effective deterrent to methanogenic bacterial activity [17].

Continual Methane Seepage

In most SPR caverns, the gas present in the crude oil is believed to have accumulated during cavern development as pockets of gassy salt were encountered, and as "air" dissolved in the water used to leach the caverns came out of solution due to the salting-out effect. Further gas intrusion into stored crude oil in these caverns is expected to diminish as gas present in intersected pockets is depleted. During cavern development, especially at Bryan Mound and Big Hill, considerable quantities of gas were encountered while drilling some wells. These caverns are thought to intersect anomalous zones or lenses of sandstone or other sediments that may be acting as conduits for gases present in deep seated pockets or for high pressure gases present in traps on the flanks of the dome. The buildup of wellhead pressure expected as a result of cavern creep and geothermal warming of the stored crude oil is too low to account for what has been observed. In these caverns, gas intrusion could continue over the lifetime of the program. A monitoring program is being developed to determine the rate of gas buildup and whether it diminishes over time. Several years will be required to obtain meaningful data in this monitoring program.

IMPACT OF GEOTHERMAL HEATING ON TRUE VAPOR-PRESSURE OF SPR CRUDE OIL

A regulatory maximum on crude oil TVP of 11 psia has been established by the U.S. Environmental Protection Agency, and adopted by the Texas Air Quality Board and the Louisiana Department of Environmental Quality. Further, one of the commercial marine terminals serving the SPR has adopted a maximum TVP of 10.5 psia for its crude oil operations. From an operational standpoint, oil with a TVP in excess of 14.7 psia (atmospheric pressure) could foam in tanks possibly causing damage to floating roofs. Atmospheric emissions would also be excessive and could pose a safety hazard, especially when the crude contains H_2S.

Temperature of oil in some caverns at Bryan Mound and Bayou Choctaw is presently high enough so that its TVP at the delivery point will likely exceed regulated or safe operating limits, even in the absence of extraneous gases. In the near-term, design drawdown rates can be achieved for both Bryan Mound and Bayou Choctaw with temperature blending and selected distribution scenarios. To achieve unrestricted drawdown in the long-term, some means of cooling the oil will be needed. Modelling studies indicate that a simple tube-in-shell heat exchanger which utilizes the surface water used for drawdown will cool oil sufficiently so that its TVP does not exceed 11 psia at the delivery point. Preliminary data from these studies indicate that reduced flow rates alone may impart the necessary degree of cooling, but only for a short time.

There does not appear to be a near- or long-term problem with temperature of oil from Weeks Island mine. Because of the relative shallowness of Weeks Island mine, the stored oil is unlikely to become heated to the point at which its TVP will exceed environmental or safe operating limits. The TVP of gas-free oil from Bayou Choctaw, Big Hill, and West Hackberry probably will not exceed 11 psia because of cooling in the well bore during drawdown and in pipelines during transport between the sites and certain terminals. Some cooling of the oil may be necessary for its delivery to nearby refineries or terminals.

Reconfiguration of slick-hole wells to include a brine stringer would provide some cooling during sustained drawdown at design rates. The degree of cooling thus attained would not, however, allow for unrestricted distribution. Moreover, reconfiguration of wells does not compare favorably on a cost basis with tube-in-shell heat exchangers, and will result in greater cavern workover and recertification costs.

For future purchases of crude oil, it has been suggested that a lower Reid vapor pressure (RVP) be stipulated in SPR crude oil purchase specifications. This measure likely would drastically reduce the market base of acceptable crude oils. At export terminals such as Sullom Voe, crude oil is stabilized to just below 11 psi as a practical matter which balances safety, environmental, and economic considerations of producers, transporters, and refiners. It is also common practice at many terminals to occasionally include some natural gas liquids, but not methane, in the crude stream.

INDUSTRY IMPACTS STEMMING FROM HOT AND GASSY OIL

Crude oils are stabilized at the time they are produced so that they can be handled more safely and also to minimize atmospheric emissions. Virtually all methane and other “noncondensable” gases such as nitrogen, as well as considerable ethane, are removed during this stabilization process. The resulting crude has a TVP of less than approximately 13 psia.

Tankers are not built to handle crude oils with vapor pressures in excess of about 14.7 psia. With a high TVP crude oil excessive emission of gases could occur from gage hatches posing a safety hazard, or a fire or explosion risk. Crude oil tanks at terminals and in refineries typically have floating roofs to minimize atmospheric emissions. Floating roofs could be damaged by foaming of crude oil that has a vapor pressure in excess of approximately 15 psia at high flow rates. Geodesic dome tanks equipped with various vapor recovery systems are beginning to be used at terminals, replacing floating roof tanks. Most of these vapor recovery systems are designed for tanker unloading operations, however, and their effectiveness is negligible for propane (C,) and lighter hydrocarbons or nitrogen.

During distribution of gassy crude oil by pipeline, pump cavitation could occur if vapor pressure exceeds the suction pressure, and could possibly result in damage to pumps. Some pipeline operators have RVP limitations of 13 psia on crude containing "indirect liquids." Others include language in their tariff conditions to the effect that when streams "contain indirect liquids, vapor pressure shall not exceed that permitted by Carrier's facilities and operating conditions." These limitations could effectively preclude pipeline shipment of a large volume of SPR crude oil at the present time. At a refinery, processing of a high vapor pressure or gassy crude could result in some reduction of separation efficiency in the atmospheric pipe still and, possibly, overloading of the downstream gas separation plant. These conditions are not dangerous but could result in reduced throughput.

CONCLUSIONS

The quality of SPR crude oil stocks is unaffected, except for an increase in vapor pressure caused by the intrusion of gases and geothermal heating. Vapor pressure of the crude oil can be lowered somewhat during drawdown by cooling using conventional tube-in-shell heat exchangers. The surface water used for displacing the crude oil from caverns would be used as coolant. Despite the relatively small volume of gas present in SPR crude oil stocks, design flow rates make its removal during a full-scale drawdown an impracticable and highly expensive option. Accordingly, the crude oil inventory in certain caverns will be degassed during the next several years using skid-mounted stabilization trains with a throughput of approximately 100,000 barrels per day. Stabilization will essentially comprise a simple atmospheric flash with, perhaps, some vacuum assist or moderate heating. The separated gases will be incinerated. This stabilized crude oil will then be returned to storage. During a drawdown, the stabilized crude oil will be commingled with other crude oil having a low to moderate gas content so that the resultant stream has a TVP of less than atmospheric pressure at the delivery temperature. Conceivably, several SPR caverns may have to be abandoned because of continual moderately large-scale gas inflows. Further study, using data from the gas monitoring program, is necessary before a decision can be made with regard to cavern abandonment.

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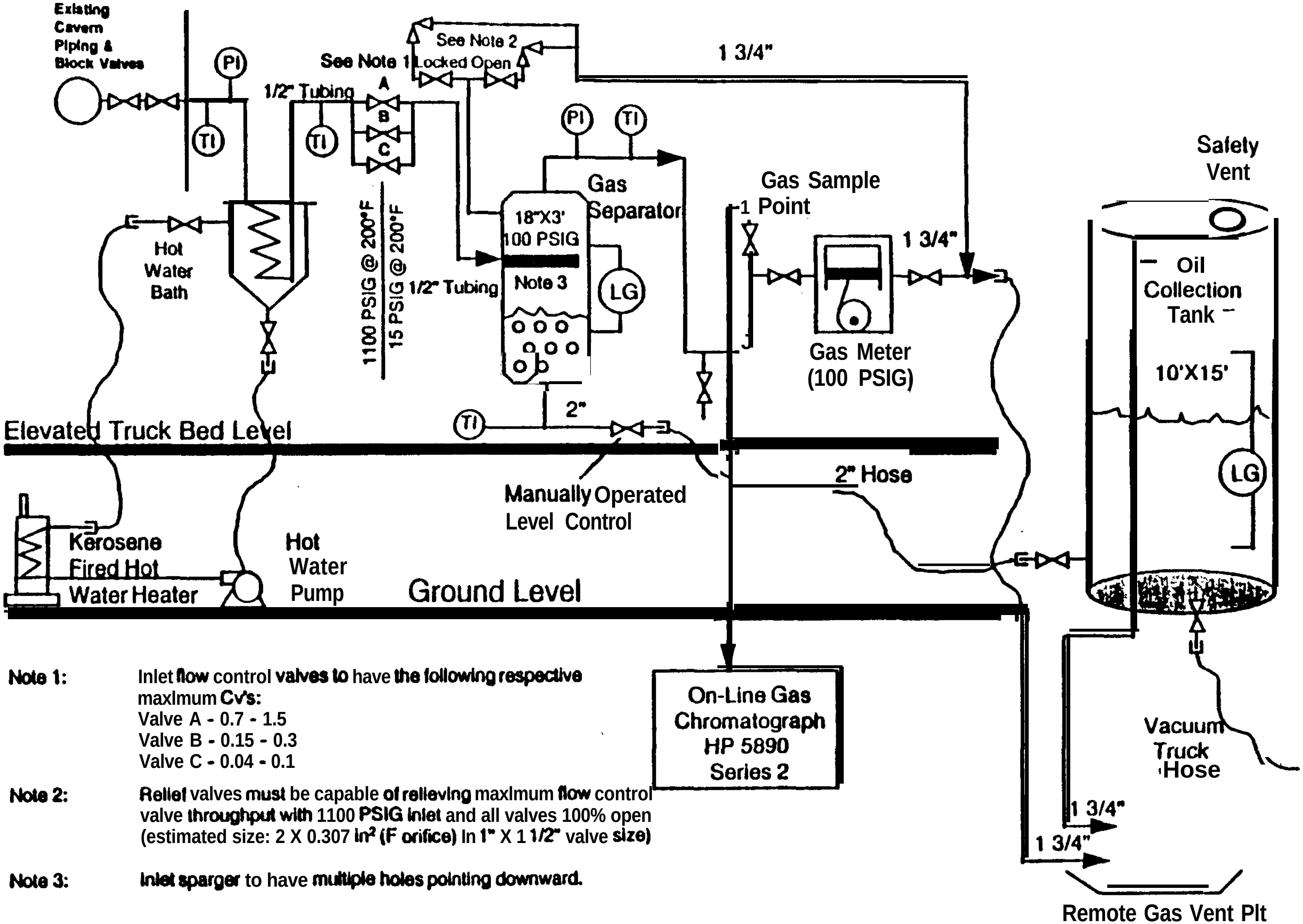

Note 1: Inlet flow control valves to have the following respective maximum Cv's:
Valve A - 0.7 - 1.5
Valve B - 0.15 - 0.3
Valve C - 0.04 - 0.1

Note 2: Relief valves must be capable of relieving maximum flow control valve throughput with 1100 PSIG inlet and all valves 100% open (estimated size: 2 X 0.307 in^2 (F orifice) In 1" X 1 1/2" valve size)

Note 3: Inlet sparger to have multiple holes pointing downward.

Figure 1. Schematic of Pilot Plant Gas-Oil Separator.

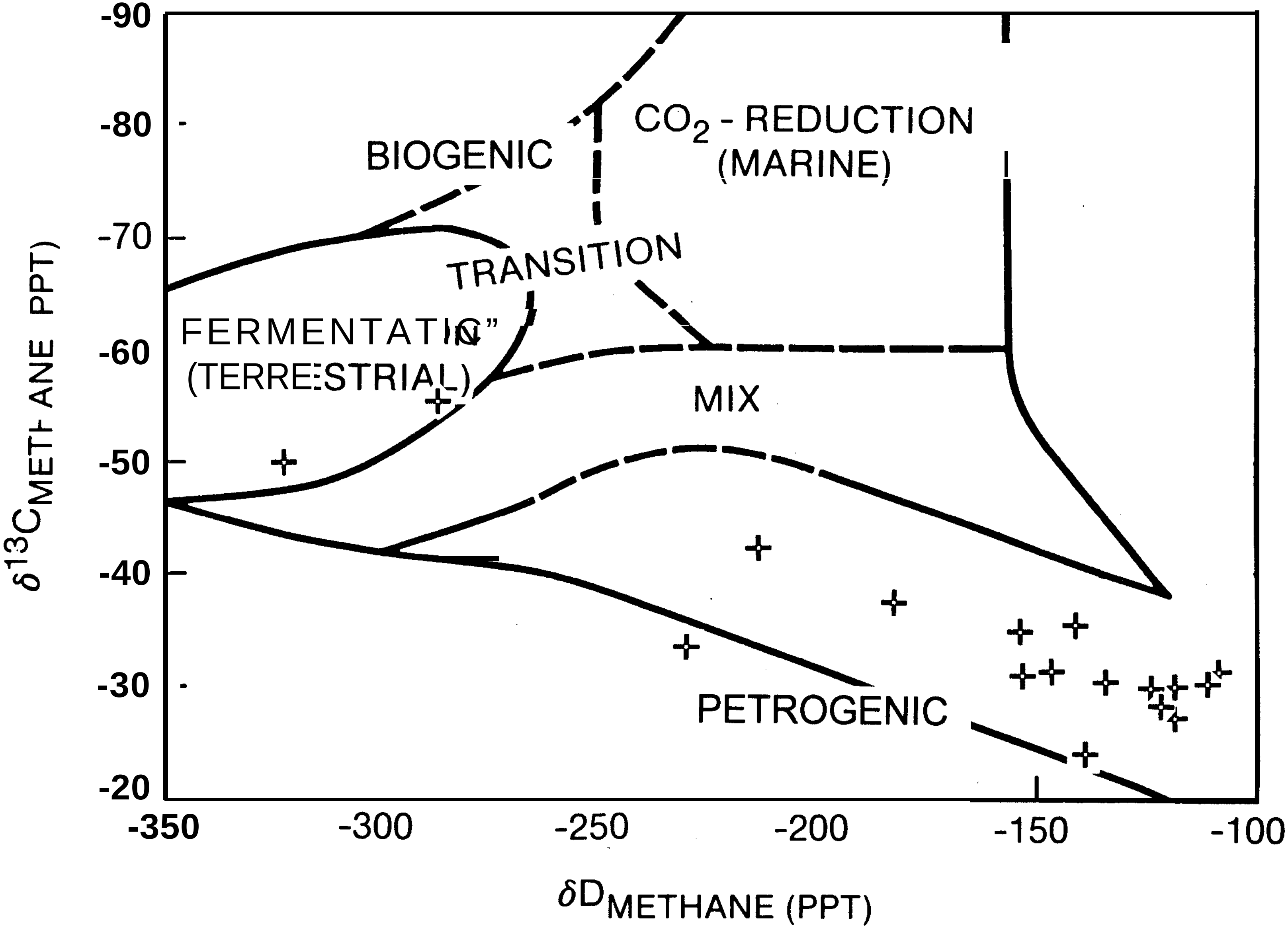

Figure 2. Genetic classification of methane using **δD** and **δ** 13C stable isotope ratios (based on Whiticar and others, 1986 **[16])**.

Appendix 6

Correlation of Gassy Caverns and Anomalous Zones in Salt

CORRELATION OF GASSY CAVERNS AND ANOMALOUS ZONES IN SALT

Background

In early 1993 it was evident that a number of caverns within the SPR system had excessive amounts of gaseous hydrocarbons dissolved in the oil. The oil will require degassing prior to refining in many cases, and because the processing rate may be less than drawdown rate criteria, cycling of oil and concomitant degassing is anticipated in order to maintain readiness [Oil and Gas Journal, 1993]. In a number of instances the gas content had increased, leading to the conclusion that the source could be from within the salt. Gas in salt has long been a problem in conventional mining, leading to several fatal accidents following outbursts of gas and associated saltfalls [Molinda, 1988]. Gas outbursts are also believed to have occurred during solution mining of storage caverns [Thorns and Martinez, 1978].

Bayou Choctaw

At Bayou Choctaw, Caverns 18 and 20 showed higher than allowable gas content in March and May, 1993, and were identified as requiring treatment prior to drawdown. A possible correlation of gassy caverns and the N 75° E trending shear zone shown on Figure 6 exists, similar to that occurring at Bryan Mound [Thorns, 1993]. This correlation is also similar to that noted by Iannacchione et al. [1984] in his study of gas associated with salt outbursts in conventional mining, wherein he measured concentrations 200 times that found in normal salt away from anomalous zones. This correlation suggests that gas may migrate through these anomalous zones and into the adjacent salt at a faster rate than in normal salt. At Bayou Choctaw Caverns 18 and 20 are evidently in the salt adjacent to the anomalous zone. Cavern 20 is also located near the edge of the salt and adjacent to gas-producing sands which also leak gas into water wells [Neal and Magorian, 1993]. The combination of exterior location astride an anomalous zone may create conditions especially conducive to gas penetration. The rate of increase in gas content in these two caverns is unknown but will be monitored in the future, HCN 07/08/93 P07984.12

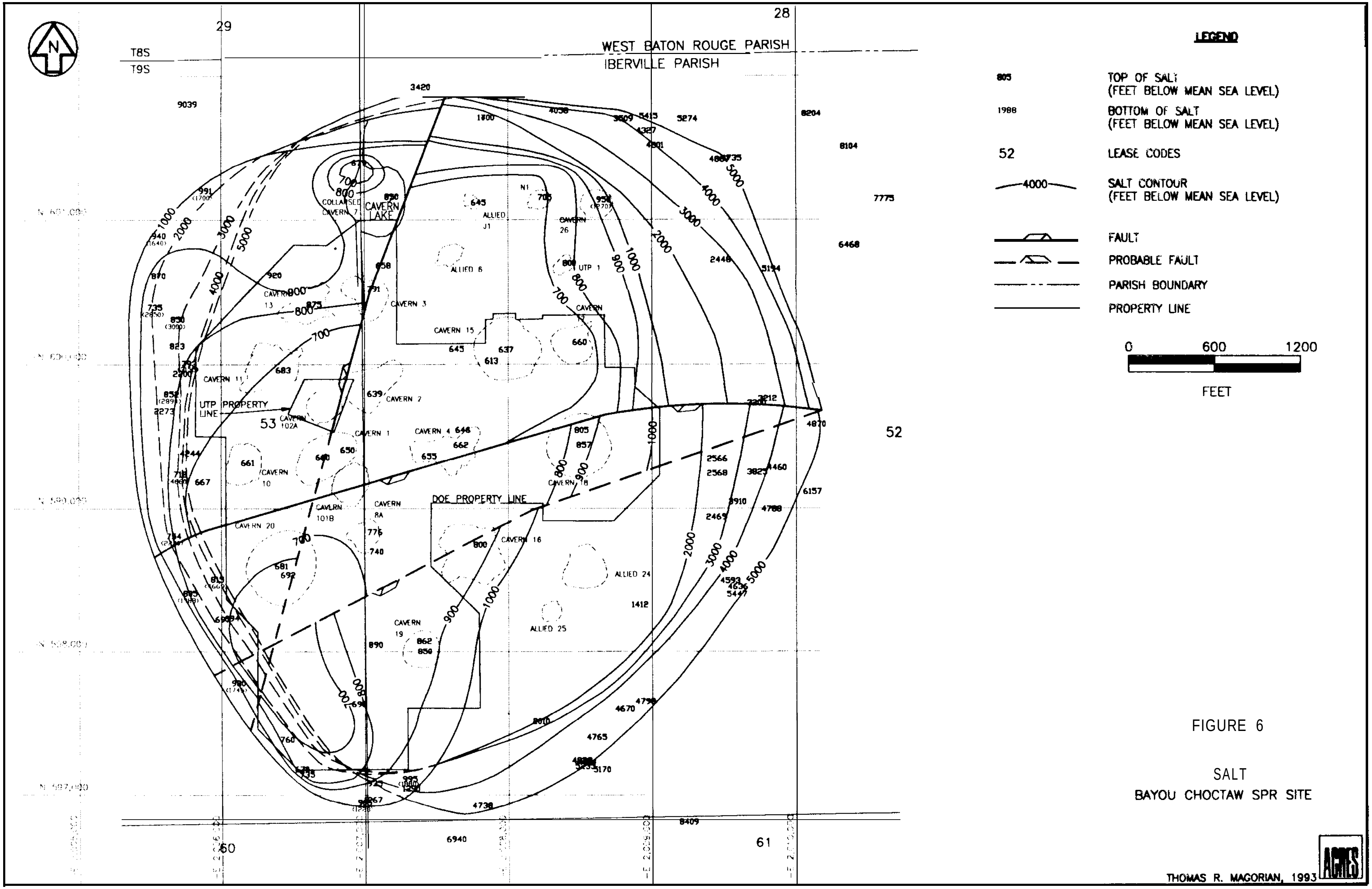

FIGURE 6

SALT
BAYOU CHOCTAW SPR SITE

Bryan Mound

Thorns (in Neal et al., 1993) believes there is a correlation of gassy caverns and anomalous zones at Bryan Mound. There are also gassy caverns that cluster in areas not necessarily identified as being "anomalous." The problem is that we really know very little detail about the occurrence and area1 extent of these so called "anomalous features." However, it is obvious that there is some preferential clustering of gassy caverns and this supports the notion that there is a likely geological cause for the occurrence.

West Hackberrv

At West Hackberry there is a similar clustering of gassy caverns near the intersection of the possible anomalous zones mapped by Magorian [Magorian and Neal, 1991]. Again the correlation is weak, but the conceptualization of anomalous zones is also fragile here.

Big Hill

Nothing conclusive can be said about Big Hill, as the oil is either blanket or that transferred from Sulphur Mines. There are anomalous zones that occur here [Neal et al., 1993] and which could affect future gas-in-oil decisions.

Conclusions

Thus a tentative association of anomalous zones and gas-in-caverns appears to exist at several of the SPR sites, but caution is needed in making specific claims. Clearly there seem to be geological factors that are causing the clustering or alignment of gassy caverns at Bayou Choctaw, Bryan Mound, and West Hackberry. As we study Bryan Mound in coming months, perhaps some answers may come forth. We need some analytical work with samples that are in the Texas Bureau of Economic Geology Core Library in Austin.

References

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Thorns, R. L. (1993) Effects of Anomalous Features (AFs) on Solution Mining of Storage CAverns in Domal Salt; p. 41-53 in Neal et al., Anomalous Zones, 1993.

Appendix 7

Projections of Future Gas Content in SPR Caverns

Sandia National Laboratories
Albuquerque, New Mexico 87185

Date: Mar. 22, 1994

To: L. J. Rousseau - DOE/SPR/PMO

Thomas E. Hinkebein

From: T. E. Hinkebein - 6 113

Subject: Projections of Future Gas Content in SPR Caverns

Summary

In response to your request, we have estimated the historical gas intrusion rates in SPR caverns. This rate information has previously been transmitted to DOE. This letter gives the methods used to determine these rates. Our goal is to be able to use this rate information to estimate the regain time after the initial degassing of oil in a cavern. To this end we have determined the amount of gas that will cause offgassing in stabilized oil. Knowing the gas content that will cause offgassing, we will then be able combine this information with the gas intrusion rate to predict the time period before retreatment is required.

Because of the uncertainly in the historical intrusion rates as well as in the laboratory bias assumptions, there is also uncertainty in the estimates of retreatment periods. Because of this uncertainty it is our intention to update these estimates as new data become available. Further, the lack of understanding about the magnitude of the laboratory bias and the intrusion rates lead us to view the regain time estimates presented in this memo as order of magnitude estimates.

Lastly, we have presented the intrusion rates in terms of the rise in the bubble point of the oil. The bubble point is preferred to the GOR because it is approximately a linear function of the mass of methane intrusion. Additionally, with equal amounts of gas intrusion the rise in the bubble point is found to be the same in both untreated oil and degassed oil. Since the Vapor Pressure Task Force (VPTF) plans to make future measurements of gas content in oil with a standardized bubble point measurement tool, it is recommended that future measurements of the gas content be described by the bubble point.

Gas Intrusion Rate Calculations

This rate information has been computed as shown on the attached spreadsheet (Table 1) with the following assumptions:

(1) The oil filled date, Column 2, was generally obtained from the 'Morning Book' for the condition where the oil volume in a particular cavern exceeded 1 MMB. In the case of unfilled Big Hill caverns the completion of first reverse was used to select the start time.

(2) The lab gas content of the oil in each cavern, Column 4, was obtained from the August 6, 1993 data sheets (Attachment 1). Because the phase III data was believed to be the most consistent complete set of data, this information was used rather than using an average of the

lab data or a compilation of lab data and skid data. On the attached sheets the phase III data is denoted "O-C" in the sample location column, i.e., the third set of surface samples.

(3) In order to compute the amount of gas intrusion, these gas contents were adjusted for a lab bias in accordance with the VPTF convention. It is observed that the skid data is thermodynamically more consistent than the lab data and more accurately represents the gas content of the crude oil. Additionally, the lab data were adjusted to receipt temperature (≈ 80°F). At this temperature it is presumed that the initial gas content of the oil was zero. *(As determinedfrom skid data, the gas content of incoming Brent crude had a GOR of zero at approximately 78°F and started to off-gas at higher temperatures.)* The adjustment for lab bias was obtained by comparing the skid data to the lab data for the following caverns: BM2 (surface, S), BM5 (coil tubing unit, CTU), BM103 (CTU), BM111 (CTU), BH101 (S), BH106 (S), BH111 (S), WH7 (CTU), WH102 (S), WH109 (S), WH1 16 (S), and WI-II 17 (CTU). For each of these caverns, a lab bias was determined by adjusting the skid data to laboratory temperature and then subtracting this value from the lab value for the GOR. The temperature adjustment of the skid data was performed empirically using skid data. **The resulting bias had an** average **value of 2.47 SCF/BBL with a standard deviation of 1.9 SCF/BBL**. This bias was subtracted from each of the lab gas content values given in Column 4. The corrected lab gas contents are shown in Column 5.

(4) The historical GOR rise per year is given in Column 7. This value was obtained by dividing the adjusted gas content by the time that the cavern has been accumulating gas (Column 6). Because the adjusted gas content only considers gas intrusion in excess of the initial gas content, this number takes into account only the gas coming from intrusion and not that from thermal effects. Additionally, this intrusion number is expressed in standard cubic feet per barrel of oil when the oil is evolving gas at ≈ 80°F.

(5) The likely future GOR rise per year, Column 8, is approximated as one-half of the historical rise. The permeability intrusion model of Ehgartner (memo to J. K. Linn, dated May 5, 1993) predicts that the future intrusion rate is reduced as the zone near the cavern is depleted of gas and the concentration gradient is reduced. Ehgartner's model projects that the intrusion rate for the second ten years will be approximately one-half of the intrusion rate for the initial ten-year period. Hence, projected intrusion rates are assumed to be one-half of the historical rate.

Significance of the Gas Content in Oil

In order to determine the effect of this gas intrusion on future needs for degassification, a series of flash calculations were performed. These calculations were used to establish several relationships which are described below. These relationships are then used to determine when additional degassing may be required.

(a) The first of these relationships is that between the mass of gas which intrudes into oil stabilized at 80°F and the resultant gas-oil ratio and the bubble point, also measured at 80°F.

(b) The second relationship is that between the mass of intruding gas and the gas-oil ratio and the bubble point, measured at 100°F, of oil that has been stabilized to a bubble point of 12.2 psia.

By combining (a) and (b) to eliminate the mass of intruding gas, a relationship is obtained between the historical gas intrusion at 80°F and the future GOR at 100°F in oil stabilized at a bubble point of 12.2 psia. In order to capture this relationship graphically, the future GOR is plotted against time using the historical intrusion rate as a parameter on the plot of Figure 1. In this figure we have plotted the future GOR versus time for the intrusion rate of 0.4 SCF/BBL/year. Other intrusion rates will yield similar plots.

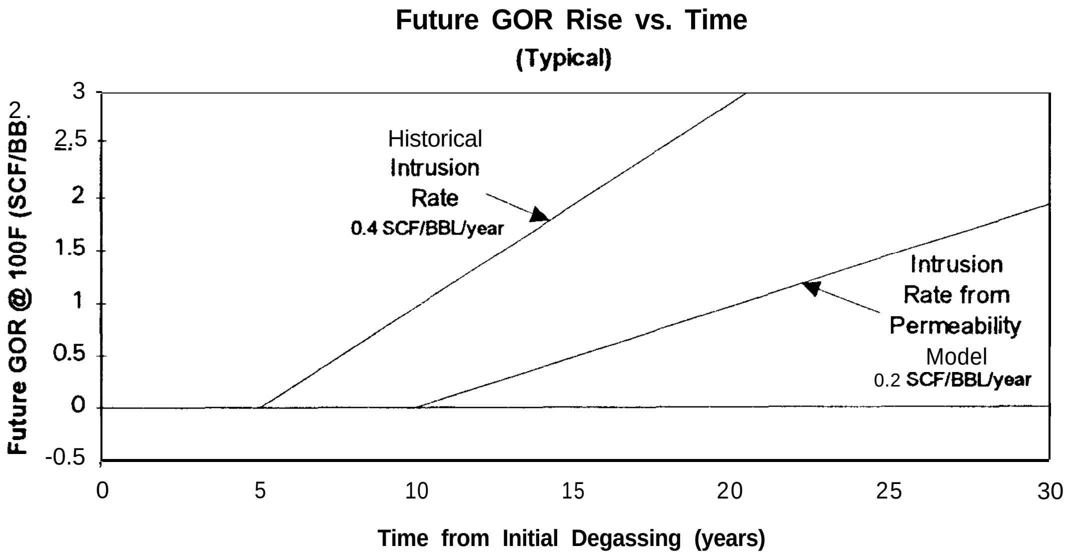

Figure 1. Plot of the future GOR in oil initially degassed to a bubble point of 12.2 psia at 100°F versus time. The historical gas intrusion is measured in SCF/BBL for oil stabilized at 80°F. The future GOR is shown on this plot as a region bounded on the left by the historical intrusion rate and on the right by the intrusion rate determine from a permeability model (one-half of the historical rate). These projected gas intrusion rates are obtained from Columns 7 and 8 in Table 1. The future GOR is plotted as a region to convey the uncertainly associated with the future intrusion rate.

From Figure 1 the regain time, i.e., the tune that it takes for the cavern to become gassy again, is the time at which the rate curves depart from the zero line. In Figure 1 the historical intrusion rate line crosses the zero line at 5 years. The line representing the intrusion rate from the permeability model crosses the zero line at 10 years. Hence, for a intrusion rate of 0.4 SCF/BBL/year the regain time is between 5 and 10 years. This same information is presented for a variety of intrusion rates in Figure 2.

Regain Time versus Historical Intrusion Rate

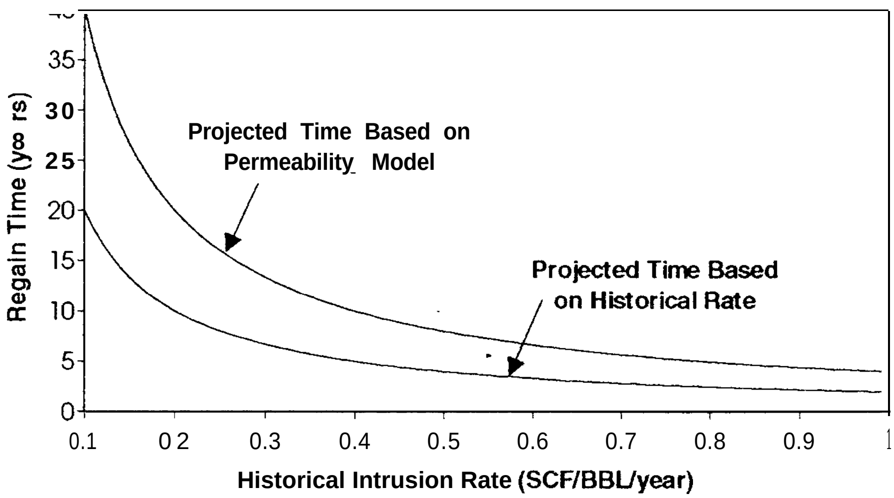

Figure 2. Plot of historical intrusion rate versus regain time. The historical intrusion rate is based on the GOR rise of 80°F stabilized oil, and the regain time is based on oil initially degassed to a bubble point of 12.2 psia at 100°F. The historical gas intrusion rates are obtained from Columns 7 in Table 1. For example. if the historical intrusion rate is 0.2 SCF/BBL/year, then the regain time based on the historical rate is projected to be 10 years and the regain time based on the permeability model is projected to be 20 years.

Significance of the Bubble Point of Oil

The future measurements of the gas content of SPR crude oil will likely use an automated bubble point measurement tool, such as ARCO-Piano's bubble point apparatus. Because the output of this machine will be the bubble point of the oil at 100°F, the rate of bubble point increase of the stabilized oil at 100°F must be related to the rate of bubble point increase for the untreated oil, also at 100°F. From flash calculations it is found that *the rate of bubble point increase for the untreated oil. is equal to the rate of bubble point increase for the treated oil.* Because of the simplicity of this relationship and the anticipated standardization of the bubble point measurement technique, it is recommended that future measurements of the gas content be described by the bubble point.

copy to:

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R. W. Lynch - 6100
J. K. Linn - 6113
J. L. Todd - 6113
Staff- 6113

Table 1

BRYAN MOUND CAVERN	START OIL FILLED	OIL VOLUME (MMB)	Lab Gas Content (SCF/BBL)	Adj. GAS CONTENT (SCF/BBL)	TIME IN CAVERN	Historical GOR Rise per year	Likely Future GOR rise per year
1	Ott-78	7.75	2.5	0.03	15.01	0.00	0.00
2	Dee-77	5.92	8.9	6.43	15.84	0.41	0.20
4	Dee-77	19.64	2.6	0.13	15.84	0.01	0.00
5	Ott-87	34.07	2.8	0.33	6.01	0.05	0.03
101	Aug-83	9.44	2.4	0.00	10.18	0.00	0.00
102	Ott-83	9.79	2.8	0.33	10.01	0.03	0.02
103	Mar-83	9.95	7.5	5.03	10.59	0.47	0.24
104	Apr-82	10.29	1.9	0.00	11.51	0.00	0.00
105	Apr-82	9.43	2.1	0.00	11.51	0.00	0.00
106	Oct-81	11.12	1.4	0.00	12.01	0.00	0.00
107	Feb-82	10.32	2.5	0.03	11.67	0.00	0.00
108	May-83	10.83	2	0.00	10.43	0.00	0.00
109	Aua-82	10.56	2.8	0.33	11.18	0.03	0.01
110	Dec-81	10.14	1.7	0.00	11.84	0.00	0.00
111	Jut-84	9.86	5.7	3.23	9.26	0.35	0.17
112	Jun-84	9.56	16.6	14.13	9.34	1.51	0.76
113	Jul-87	4.57	2.9	0.43	6.26	0.07	0.03
114	Jan-87	7.14	3.4	0.93	6.75	0.14	0.07
115	Jan-87	8.01	2.7	0.23	6.75	0.03	0.02
116	Jan-87	8.65	4.3	1.83	6.75	0.27	0.14
WEST HACKBERRY							
CAVERN							
6	Nov-77	7.13	1.2	0.00	15.93	0.00	0.00
7	Ott-78	12.59	2.1	0.00	15.01	0.00	0.00
8	Dec-78	9.96	1.5	0.00	14.84	0.00	0.00
9	Nov-78	9.3	1.2	0.00	14.93	0.00	0.00
11	Ott-77	8.27	1.4	0.00	16.01	0.00	0.00
101	Aug-82	9.79	2.4	0.00	11.18	0.00	0.00
102	Sep-83	10.17	1.9	0.00	10.09	0.00	0.00
103	Sep-82	8.74	2.5	0.03	11.09	0.00	0.00
104	Ott-82	10.09	2.3	0.00	11.01	0.00	0.00
105	Nov-82	9.93	2.4	0.00	10.92	0.00	0.00
106	Nov-85	8.97	1.4	0.00	7.92	0.00	0.00
107	Jul-83	10.81	1.9	0.00	10.26	0.00	0.00
108	Jun-83	8.76	2.5	0.03	10.34	0.00	0.00
109	Nov-86	10.46	1.7	0.00	6.92	0.00	0.00
110	Dee-83	9.87	2.2	0.00	9.84	0.00	0.00
111	Mar-87	7.21	1.6	0.00	6.59	0.00	0.00
112	Jun-85	9.15	1.7	0.00	8.34	0.00	0.00
113	Jul-84	4.38	2.6	0.13	9.36	0.01	0.01
114	Ott-84	9.94	1.7	0.00	9.01	0.00	0.00
115	Aug-86	10.02	1.9	0.00	7.17	0.00	0.00
116	Mar-85	9.4	2.5	0.03	8.59	0.00	0.00
117	Jul-88	9.7	1.6	0.00	5.25	0.00	0.00

Table 1

BIG HILL							
CAVERN							
101	Feb-89	1.94	2.6	0.13	4.67	0.03	0.01
1021	Am-89	3.33	10.9	8.43	4.50	1.87	0.94
103	May-89	0.28	3.3	0.83	4.42	0.19	0.09
104	Mar-89	0.78	10.9	8.43	4.59	1.84	0.92
105	Ott-88	0.39	6	3.53	5.00	0.71	0.35
106	Mar-89	5.7	3.1	0.63	4.59	0.14	0.07
107	Ott-88	9.12	5.9	3.43	5.00	0.69	0.34
108	Jan-89	9	4.2	1.73	4.75	0.36	0.18
109	Jan-89	0.52	5.9	3.43	4.75	0.72	0.36
110	Nov-88	2.11	4	1.53	4.92	0.31	0.16
111	Apr-90	0.01	15.8	13.33	3.50	3.80	1.90
112	Mir-90	0.01	8.7	6.23	3.59	1.74	0.87
113	Mar-90	0.62	7.3	4.83	3.59	1.35	0.67
1141	Apr-90	0.03	6.6	4.13	3.50	1.18	0.59
BAYOU CHOCTAW							
15	Jan-78	15.83	1.9	0.00	15.76	0.00	0.00
171	Apr-87	9.3	2	0.00	6.51	0.00	0.00
18	Dec-78	4.93	3.5	1.03	14.84	0.07	0.03
19	Nov-78	10.09	2.5	0.03	14.93	0.00	0.00
20	May-81	6.7	4.1	1.63	12.43	0.13	0.07
101	Oct-88	4.75	2.3	0.00	5.00	0.00	0.00

Attachment 1

BAYOU CHOCTAW CRUDE OIL ANALYTICAL DATA

CAVERN	CRUDE TYPE	INVENTORY (MMB)	1993 PROJ. TEMP. (F)	SAMPLE LOCATION (FT)	GOR (SCF/BBL)	BUBBLE POINT (BP) PRESSURE (PSIA)	@ TEMP. (F)	RVP (PSIA)	GOR @100°F (ACF/BBL)	BP @100°F (PSIA)	SAMPLE DATE (MO/YR)
18	SWEET			O-A	3.6	20	72				3-93
18	SWEET			O-B	3.2	161	67				3-93
18	SWEET			O-C	3.5	21	71	9.1			3-93
18	SWEET	4.93	90	AVG	3.4	19	70	9.1 •	10.6	23	
20	SWEET			O-A	3.5	25	65				3-93
20	SWEET			O-B	4.0	31	72				3-93
20	SWEET			O-C	4.1	32	72	8.8			3-93
20	SWEET			-3830-A							5-93
20	SWEET			-3830-B							5-93
20	SWEET	6.70	106	AVG	3.9	29	70	9.0	11.1	33	
101	SWEET			O-A	3.0	15	68				3-93
101	SWEET			O-B	3.5	23	71				3-93
101	SWEET			O-C	2.3	21	67	9.2			3-93
101	SWEET	4.45	101	AVG	2.9	20	69	9.2 *	10.1	23	
15	SOUR			O-A	2.1	17	70				3-93
15	SOUR			O-B	1.7	14	71				3-93
15	SOUR			O-C	1.9	21	70	6.3			3-93
15	SOUR			-2605-A							5-93
15	SOUR			-2605-B							5-93
15	SOUR			-2805-C							5-93
15	SOUR	15.831	98	AVG	1.9	17	70	6.2	9.1	21	
17	SOUR			O-A	2.4	18	71				3-93
17	SOUR			O-B	2.1	17	71				3-93
17	SOUR			O-C	2.0	19	70	7.0			3-93
17	SOUR	9.30	69	AVG	2.2	18	71	7.0 *	9.4	22	
19	SOUR			O-A	1.8	14	66				3-93
19	SOUR			O-B	2.1	21	73				3-93
19	SOUR			O-C	2.5	18	71	6.7			3-93
19	SOUR			-2935-A							5-93
19	SOUR			-2935-B							5-93
19	SOUR			-2935-C							5-93
19	SOUR	10.90	100	AVG	2.1	18	70	6.0	9.3	21	

NOTES: • RVP OBTAINED FROM THE MOST RECENT SURFACE SAMPLING

EFFECTIVE DATE :06-Aug-93

BIG HILL CRUDE OIL ANALYTICAL DATA

CAVERN	CRUDE TYPE	INVENTORY (MMB)	1993 PROJ. TEMP. (F)	SAMPLE LOCATION (FT)	GOR (SCF/BBL)	BUBBLE POINT (BP) PRESSURE @ (PSIA)	BUBBLE POINT (BP) TEMP. (F)	RVP (PSIA)	GOR @100°F (ACF/BBL)	BP @100°F (PSIA)	SAMPLE DATE (MO/YR)
101	SWEET			0-A	2.6	29	65				3-93
101	SWEET			0-B	4.3	26	72				3-93
101	SWEET			0-C	3.6	34	68	9.1			3-93
101	SWEET	1.94	N/A	AVG	3.5	30	68	9.1 *	10.7	33	
102	SWEET	3.33	N/A	ESTIMATE	10.7	34	100	5.0 **	17.9	34	
103	SWEET			0-A	3.3	19	70				3-93
103	SWEET			0-B	3.6	22	71				3-93
103	SWEET			0-C	2.4	23	70	8.5			3-93
103	SWEET	0.28	N/A	AVG	3.1	21	70	8.5 *	10.3	25	
104	SWEET	0.78	N/A	ESTIMATE	10.7	34	100	5.0 **	17.9	34	
105	SWEET			0-A	6.0	36	69				3-93
105	SWEET			0-B	5.9	37	72				3-93
105	SWEET			0-C	6.0	36	68	8.9			3-93
105	SWEET	0.39	N/A	AVG	6.0	36	70	8.9 *	13.2	40	
110	SWEET			0-A	4.0	29	88				3-93
110	SWEET			0-B	4.8	29	72				3-93
110	SWEET			0-C	3.8	32	68	9.3			3-93
110	SWEET	2.11	N/A	AVG	4.2	30	69	9.3 *	11.4	34	
106	SOUR			0-A	2.1	32	65				1-93
106	SOUR			0-B	2.5	28	61				1-93
106	SOUR			0-C	2.1	32	66				1-93
106	SOUR			-2295-A	2.6	30	62				1-93
106	SOUR			-2295-B	3.1	29	60				1-93
106	SOUR			-2295-C	2.5	33	59				1-93
106	SOUR			0-PP-A	3.7	38	68				4-93
106	SOUR			0-PP-B	3.1	39	72				4-93
106	SOUR	5.70	86	PP	3.1	25	100	6.2	3.3	25	
107	SOUR			0-A	2.1	21	61				1-93
107	SOUR			0-B	2.2	22	67				1-93
107	SOUR			0-C	1.6	23	59	6.3			1-93
107	SOUR	9.12	86	AVG	2.0	22	62	6.3	9.2	27	
108	SOUR			0-A	2.4	20	65				1-93
108	SOUR			0-B	1.5	23	61				1-93
108	SOUR			0-C	2.0	23	62	6.1			1-93
108	SOUR	9.00	88	AVG	2.0	22	63	6.1	9.2	26	

EFFECTIVE DATE :06-Aug-93

BIG HILL CRUDE OIL ANALYTICAL DATA

CAVERN	CRUDE TYPE	INVENTORY (MMB)	1993 PROJ. TEMP. (F)	SAMPLE LOCATION (FT)	GOR (SCF/BBL)	BUBBLE POINT (BP) PRESSURE @ (PSIA)	TEMP. (F)	RVP (PSIA)	GOR @100°F (ACF/BBL)	BP @100°F (PSIA)	SAMPLE DATE (MO/YR)
109	SOUR			O-A	5.9	41	70				3-93
109	SOUR			O-B	6.0	41	73				3-93
109	SOUR	b52 .	89	O-C / AVG	4.2 / 5.4	43	68	7.0 •			3-93
						42	70	7.0	12.6	45	
111	SOUR			O-A / O-B	15.8	68	70				3-93
					13.1	70	67				3-93
111	SOUR			o - c	12.5	70	70	6.4			3-93
111	SOUR			0-PP-A	13.1	91	64				4-93
111	SOUR			0-PP-B	13.3	87	65				4-93
111	SOUR	0.01	N/A	PP	15.4	67	loo	6.4 *	16.6	67	
112	SOUR			O-A	8.7	65	74				3-93
112	SOUR			O-B	11.3	64	69				3-93
112	SOUR			o - c	11.5	63	72	6.9			3-93
112	SOUR	0.01	N/A	AVG	10.5	64	72	6.9 •	17.7	67	
113	SOUR	0.62	N/A	ESTIMATE	7.1	54	70	7.3	14.3	58	
114	SOUR			O-A	6.6	57	69				3-93
114	SOUR			O-B	7.3	52	71				3-93
114	SOUR			o - c	7.5	52	71	7.3			3-93
114	SOUR	0.03	N/A	AVG	7.1	54	70	7.3 •	14.3	57	

NOTES: * RVP OBTAINED FROM THE MOST RECENT SURFACE SAMPLING
• * NPR CRUDE RVP OBTAINED FROM SUN TERMINAL TESTING

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BRYAN MOUND CRUDE OIL ANALYTICAL DATA

CAVERN	CRUDE TYPE	INVENTORY (MMB)	1993 PROJ. TEMP. (F)	SAMPLE LOCATION/ (FT)	GOR (SCF/BBL)	BUBBLE POINT (BP) PRESSURE (PSIA)	@ TEMP.	RVP (PSIA)	GOR @100°F (ACF/BBL)	BP @100°F (PSIA)	SAMPLE DATE (MO/YR)
1	SWEET			O-A	[illegible]	25	[illegible]				3-93
1	SWEET			O-B	2.8	15	68				3-93
1	SWEET			o-c	2.5	23	71	8.6			3-93
1	SWEET	7.75	114	AVG	2.8	21	68	8.6 *	10.0	25	
2	SWEET			0-A	8.8	48	67				3-93
2	SWEET			O-B	6.4	35	66				3-93
2	SWEET			o-c	8.9	52	71	9.1			3-93
2	SWEET			0-PP-A	9.1	78	60				4-93
2	SWEET			0-PP-B	9.1	77	63				4-93
2	SWEET	5.92	110	PP	12.4	34	66	7.7	13.4	42	
4	SWEET			O-A	4.1	16	69				3-93
4	SWEET			O-B	2.2	15	60				3-93
4	SWEET			o-c	2.6	20	72	8.0			3-93
4	SWEET	19.64	106	AVG	3.0	17	67	9.4	10.2	21	
113	SWEET			O-A	3.6	21	63				7-93
113	SWEET			O-B	3.7	16	64				7-93
113	SWEET			o-c	2.9	24	65				7-93
113	SWEET	4.57	119	AVG	3.4	20	64	8.8	10.6	25	
114	SWEET			O-A	4.2	20	64				7-93
114	SWEET			O-B	3.1	23	61				7-93
114	SWEET			o-c	3.4	20	62				7-93
114	SWEET	7.14	121	AVG	3.6	21	62	8.3	10.8	26	
115	SWEET			O-A	3.7	16	66				7-93
115	SWEET			O-B	2.9	23	63				7-93
115	SWEET			o-c	2.7	18	64				7-93
115	SWEET	8.91	118	AVG	3.1	19	64	9.0	10.3	23	
116	SWEET			O-A	2.6	18	69				3-93
116	SWEET			O-B	3.2	17	72				3-93
116	SWEET			o-c	4.3	18	73	9.0			3-93
116	SWEET	8.65	117	AVG	3.4	18	71	8.1	10.6	21	
5	SOUR			O-A	2.1	17	68				3-93
5	SOUR			O-B	1.7	15	61				3-93
5	SOUR			o-c	2.8	20	70	7.8			3-93
5	SOUR			-2102-A							3-93
5.	SOUR	34.07,	97.	AVG	2.2.	17.	66	7.0	9.4.	211	

EFFECTIVE DATE :**06-Aug-93**

BRYAN MOUND CRUDE OIL ANALYTICAL DATA

CAVERN	CRUDE TYPE	INVENTORY (MMB)	1993 PROJ. TEMP. (F)	SAMPLE LOCATION (FT)	GOR (SCF/BBL)	BUBBLE POINT (BP) PRESSURE @ TEMP. (PSIA)		RVP (PSIA)	GOR @100°F (ACF/BBL)	BP @100°F (PSIA)	SAMPLE DATE (MO/YR)
101	SOUR			O-A	2.3	18	66				3-93
101	SOUR			O-B	3.2	21	65				3-93
101	SOUR			o-c	2.4	29	68	6.5			3-93
101	SOUR			-1998-A							3-93
101	SOUR			-1998-B							3-93
101	SOUR			-1998-c							3-93
101	SOUR	9.44	120	AVG	2.6	23	66	7.1	9.8	27	
102	SOUR			O-A	2.0	15	69				3-93
102	SOUR			O-B	2.3	15	68				3-93
102	SOUR			o-c	2.8	22	67	6.4			3-93
102	SOUR	9.79	123	AVG	2.4	17	68	7.8	9.6	21	
103	SOUR			O-A	4.4	31	71				3-93
103	SOUR			O-B	3.9	31	68				3-93
103	SOUR	.		o-c	7.5	39	73	7.5			3-93
103	SOUR			-2112-A							3-93
103	SOUR			-2112-B							3-93
103	SOUR			-2112-c							3-93
103	SOUR			0-PP-A	8.6	116	60				4-93
	SOUR			INTEGRITY OF SAMPLE LOST							4-93
103	SOUR	9.95	121	0-PP-B	7.6	34	100	4.7	8.2	34	. --
104	SOUR			O-A	1.9	17	66				3-93
105	SOUR			O-B	2.5	19	67				3-93
105	SOUR			o-c	1.9	16	70	7.3			3-93
105	SOUR	10.29	119	AVG	2.1	17	68	6.3	9.3	21	
105	S(1105H			0-C 0-A 0-B	2.1	22 221 18	71	5.9 7.0	9.1	24	3-93 3-93 3-93
	JR	9.43	121	AVG	1.9	21					
107	SOUR			O-A	1.9	17	70				3-93
107	SOUR			O-B	2.1	16	69				3-93
107	SOUR			o-c	2.5	22	72	6.8			3-93
107	SOUR	10.32	120	AVG	2.2	18	70	4.8	9.4	22	
108	SOUR			O-A	2.1	21	73				3-93
108	SOUR			0-B	1.7	21	69				3-93
108	SOUR			o-c	2.0	2 2	74	6.4			3-93
108	SOUR	10.83	119	AVG	1.9	21	72	5.0	9.1	25	

EFFECTIVE DATE: **06-Aug-93**

BRYAN MOUND CRUDE OIL ANALYTICAL DATA

CAVERN	CRUDE TYPE	INVENTORY (MMB)	1993 PROJ. TEMP. (F)	SAMPLE LOCATION (FT)	GOR (SCF/BBL)	BUBBLE POINT (BP) PRESSURE (PSIA)	@ TEMP.	RVP* (PSIA)	GOR @100°F (ACF/BBL)	BP @100°F (PSIA)	SAMPLE DATE (MO/YR)
109	SOUR			0-A	1.8	20	67				3-93
109	SOUR			O-B	1.9	22	62				3-93
109	SOUR			0-C	[illegible]	25	[illegible]	[illegible]			3-93
109	SOUR	10.56	122	AVG	2.2	22	68	6.7	9.4	26	
110	SOUR			0-A	2.2	22	68				3-93
110	SOUR			0-B	1.8	16	71				3-93
110	SOUR			0-C	1.7	21	73	7.1			3-93
110	SOUR	10.14	121	AVG	1.9	20	71	6.1	9.1	23	
111	SOUR			0-A	6.8	37	66				3-93
111	SOUR			0-B	4.7	33	66				3-93
111	SOUR			[illegible]	5.7	[illegible]	71	7.6			3-93
111	SOUR			0-PP-A	19.2	100	60				5-93
111	SOUR			0-PP-B	22.5	100	60				5-93
111	SOUR	9.86	119	PP	7.5	39	100	5.9	8.1	39	
112	SOUR			0-A	[illegible]	86	66				3-93
112	SOUR			O-B	16.6	75	72				3-93
112	SOUR			O-C		[illegible]	[illegible]	7.4			3-93
				-2065-A							3-93
112	SOUR			-2065-B							3-93
112	SOUR			-2065-C							3-93
112	SOUR			0-PP-A	7.2	42	64				5-93
112	SOUR			0-PP-R	7.2	41	61				5-93
112	SOUR	9.56	123	PP	8.6	38	100	6.0	9.3	38	
106	MAYA			O-A	[illegible]	21	64				5-93
106	MAYA	11.12	1221	AVG	1.4	21	64	5.4	8.6	25	

NOTES: * RVP OBTAINED FROM THE MOST RECENT SURFACE SAMPLING

WEST HACKBERRY CRUDE OIL ANALYTICAL DATA

CAVERN	CRUDE TYPE	INVENTORY (MMB)	1993 PROJ. TEMP. (F)	SAMPLE LOCATION (FT)	GOR (SCF/BBL)	BUBBLE POINT (BP) PRESSURE (PSIA)	@ TEMP. (F)	RVP (PSIA)	GOR @100°F (ACF/BBL)	BP @100°F (PSIA)	SAMPLE DATE (MO/YR)
7	SWEET			O-A	2.9	13	70				3-93
7	SWEET			0-B	2.6	18	71				3-93
7	SWEET			0-C	2.1	19	65	8.6			3-93
7	SWEET			0-PP-A	1.7	22	61				6-93
7	SWEET			0-PP-B	1.9	22	63				6-93
7	SWEET	12.59	111	PP	0.7	18	100	5.6	0.8	18	
101	SWEET			O-A	2.7	21	72				3-93
101	SWEET			O-B	2.5	21	70				3-93
101	SWEET			0-C	2.4	24	74	8.7			3-93
101	SWEET	9.79	124	AVG	2.5	22	72	8.1	9.7	25	
102	SWEET			0-A	3.0	16	711				3-93
102	SWEET			0-B	2.7	20	70				3-93
102	SWEET			0-C	1.9	18	58	7.5			3-93
102	SWEET			0-PP-A	1.81	141	64				6-93
102	SWEET			0-PP-B	2.1	131	61				6-93
102	SWEET	10.17	123	PP	0.56	17	100	8.2	0.6	17	
103	SWEET			O-A	3.8	27	72				3-93
103	SWEET			0-B	2.7	18	68				3-93
103	SWEET			0-C	2.5	21	75	8.8			3-93
103	SWEET	8.74	1241	AVG	3.0	22	72	8.5	10.2	25	
104	SWEET			0-A	2.9	22	71				3-93
104	SWEET			0-B	1.4	19	69				3-93
104	SWEET			0-C	2.3	22	69	8.0			3-93
104	SWEET	10.09	124	AVG	2.2	21	70	8.0	9.4	25	
105	SWEET			0-A	2.3	14	70				3-93
105	SWEET			0-B	2.3	16	69				3-93
105	SWEET			0-C	2.4	21	66	8.7			3-93
105	SWEET	9.93	125	AVG	2.3	17	68	8.3	9.5	20	
107	SWEET			O-A	3.4	22	69				3-93
107	SWEET			0-B	2.5	15	68				3-93
107	SWEET			0-C	1.9	18	56	8.8			3-93
107	SWEET			-3531-A							5-93
107	SWEET			-3531-B							5-93
107	SWEET	10.81	117	AVG	2.6	18	641	8.3	9.8	23	

WEST HACKBERRY CRUDE OIL ANALYTICAL DATA

CAVERN	CRUDE TYPE	INVENTORY (MMB)	1993 PROJ. TEMP. (F)	SAMPLE LOCATION (FT)	GOR (SCF/BBL)	BUBBLE POINT (BP) PRESSURE (PSIA)	BUBBLE POINT (BP) @ TEMP. (F)	RVP (PSIA)	GOR @100°F (ACF/BBL)	BP @100°F (PSIA)	SAMPLE DATE (MO/YR)
108	SWEET			0-A	2.7	19	71				3-93
108	SWEET			0-B	2.1	17	70				3-93
108	SWEET			0-C	2.5	22	74	8.8			3-93
108	SWEET	8.76	119	AVG	2.4	19	72	8.5	9.6	23	
110	SWEET			0-A	3.0	12	73				3-93
110	SWEET			0-B	2.6	19	71				3-93
110	SWEET			0-C	2.2	22	59	8.8			3-93
110	SWEET	9.87	111	AVG	2.6	18	68	8.4	9.8	22	
113	SWEET			0-A	2.5	21	72				3-93
113	SWEET			0-B	2.2	22	69				3-93
113	SWEET			0-C	2.6	22	71	9.0			3-93
113	SWEET	4.38	121	AVG	2.4	22	71	8.1	9.6	25	
116	SWEET			0-A	4.0	27	72				3-93
116	SWEET			0-B	2.7	15	66				3-93
116	SWEET			0-C	2.5	22	70	9.3			3-93
116	SWEET			0-PP-A	1.8	17	61				6-93
116	SWEET			0-PP-B	2.0	20	61				6-93
116	SWEET	9.40	118	PP	0.56	17	100	8.0	0.6	17	
6	SOUR			0-A	1.9	17	74				3-93
6	SOUR			0-B	1.8	13	70				3-93
6	SOUR			0-C	1.2	16	64	5.4			3-93
6	SOUR	7.13	115	AVG	1.6	15	69	5.4	8.8	19	
8	SOUR			0-A	~~1.8~~	~~10~~	~~73~~				3-93
8	SOUR			0-B	1.6	22	68				3-93
8	SOUR			0-C	1.5	16	64	6.0			3-93
8	SOUR	9.96	115	AVG	1.6	19	66	4.4	8.8	23	
9	SOUR			0-A	~~1.5~~	~~10~~	69				3-93
9	SOUR			0-B	1.9	18	68				3-93
9	SOUR			0-C	1.2	14	62	6.3			3-93
9	SOUR	9.30	115	AVG	1.6	16	65	5.2	8.8	20	
11	SOUR			0-A	2.1	14	71				3-93
11	SOUR			0-B	1.7	18	68				3-93
11	SOUR			0-C	1.4	17	64	6.3			3-93
11	SOUR	8.27	120	AVG	1.7	16	68	5.3	8.9	20	

WEST HACKBERRY CRUDE OIL ANALYTICAL DATA

CAVERN	CRUDE TYPE	INVENTORY (MMB)	1993 PROJ. TEMP. (F)	SAMPLE LOCATION (FT)	GOR (SCF/BBL)	BUBBLE POINT (BP) PRESSURE (PSIA)	@ TEMP. (F)	RVP (PSIA)	GOR @100°F (ACF/BBL)	BP @100°F (PSIA)	SAMPLE DATE (MO/YR)
106	SOUR			0-A	2.3	15	69				3-93
106	SOUR			0-B	2.1	18	66				3-93
106	SOUR			0-C	1.4	17	63	7.4			3-93
108	SOUR	8.97	113	AVG	1.9	17	66	7.0	9.1	21	
109	SOUR			0-A	2.8	16	72				3-93
109	SOUR			0-B	2.3	17	66				3-93
109	SOUR			o - c	1.7	16	65	7.7			3-93
109	SOUR			0-PP-A	1.9	17	62				6-93
109	SOUR			o-PP-B	1.8	17	61				6-93
109	SOUR	10.46	112	PP	0.56	17	loo	6.8	0.6	1 7	
111	SOUR			O-A	1.7	17	63				6-93
111	SOUR			O-B	1.7	18	63				6-93
111	SOUR			o - c	1.6	19	63	6.9			6-93
111	SOUR	7.21	106	AVG	1.7	18	63	6.9*	8.9	22	
112	SOUR			O-A	2.5	16	71				3-93
112	SOUR			O-B	2.7	14	69				3-93
112	SOUR			o - c	1.7	15	62	7.6			3-93
112	SOUR	9.15	112	AVG	2.3	15	67	7.0	9.5	19	
114	SOUR			O-A	2.2	16	71				3-93
114 114	SOUR SOUR			O-B	2.3	22	69				3-93
114	SOUR	9.94		o - c	1.7	17	66	7.6			3-93
115	SOUR		118	AVG	2.0	17	69	7.3	9.2	20	
				O-A	2.6	16	69				3-93
115	SOUR			O-B	1.9	15	68				3-93
115 115	SOUR SOUR	10.02	112	o - c AVG	2.2	17	62	7.6			3-93
117	SOUR					16	66 9	4.9	4	20	
117	SOUR			O-A O-B	2.7	22	75				3-93
117	SOUR			o - c	2.5	19	68				3-93
117	SOUR	9.60	108	AVG	1.6	20	66	7.3			3-93
					2.3	20	70	7.5	9.5	24	

NOTES: • RVP OBTAINED FROM THE MOST RECENT SURFACE SAMPLING

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WEEKS ISLAND CRUDE OIL ANALYTICAL DATA

CAVERN	CRUDE TYPE	INVENTORY (MMB)	1993 PROJ. TEMP. (F)	SAMPLE LOCATION (FT)	GOR (SCF/BBL)	BUBBLE POINT (BP) PRESSURE @ (PSIA)	TEMP. (F)	RVP (PSIA)	GOR @100°F (ACF/BBL)	BP @100°F (PSIA)	SAMPLE DATE (MO/YR)
MINE	SOUR			-737-A	0.9	14	68				6-93
MINE	SOUR			-737-B	1.0	13	65				6-93
MINE	SOUR			-737-c	1.0	14	64				6-93
MINE	SOUR	71.77	78	AVG	1.0	14	65	6.4	8.2	18	

Appendix 8

Pressurization Rates of Big Hill Wells 106 Through 110

Sandia National laboratories

Albuquerque, New Mexico 87185

date April 1, 1993

to J.K. Linn, 6113

Brian L Ehgartner

from B.L. Ehgartner, 6113

subject Pressurization Rates of Big Hill Wells 106 through 110

The experimental studies performed on the Big Hill wells 106 though 110 A,B by Beasley and Goin (SAND86-0190) provide data that may be useful in understanding gas flow into caverns. These are summarized below.

- When the wells were leak tested, 'a trace amount of gas was noted only in one well, and no significant differences in well elasticities' existed.

- Months later at the start of the study, one-half of the 10 wells monitored were classified as gassy because of ‘gas accumulation at the wellheads' and the 'pressure increase rates and volumes of brine bled from the gassy wells were roughly double' than those termed non-gassy.

- The report asserts that 'the increased volume of brine removal required to reduce pressures by a given amount (for gassy wells) is consistent with higher well elasticities, which would result from communication of brine in the well with a gas formation'.

These statements imply that gas generation was initially very low or non-existent and increased with time. I decided to plot the average pressurization rates from the wells with time to see if any notable tends are present. The time scale in the plot is the approximate number of days since the wells were completed and the pressurization rate is an average value for a pressure cycle. The pressure range over which these values were measured is very similar in all cases, starting at approximately 300 and increasing to 425 psi at the wellhead. The figure provided shows quite a difference in the pressure rates of the wells. The wells on the east side of the field were classified as gassy as they pressurized faster. The scatter in the data prevents any conclusions regarding time-dependency.

I recently simulated the mechanical behavior of well 110B using a 1-D radial model. Because there are several plausible fits to the creep constitutive equation, I modeled the well behavior using each of the three fits suggests by Wawersik (memo to Beasley 1/3/85). The M-D model that includes workhardening and recovery in the transient formulation was used. The model predicts brine pressurization rates of 0.35 to 0.75 psi/day due to creep. Since the pressure histories are similar for all of the wells, no significant difference would be expected if the other wells were simulated. Obvious in comparison to the data provided, the model grossly underpredicts the pressurization rates. Since the model is well validated, it is reasonable to conclude that the pressurization due to creep is minor and that pressurization is dominated by the influx of brine and gas into the wells.

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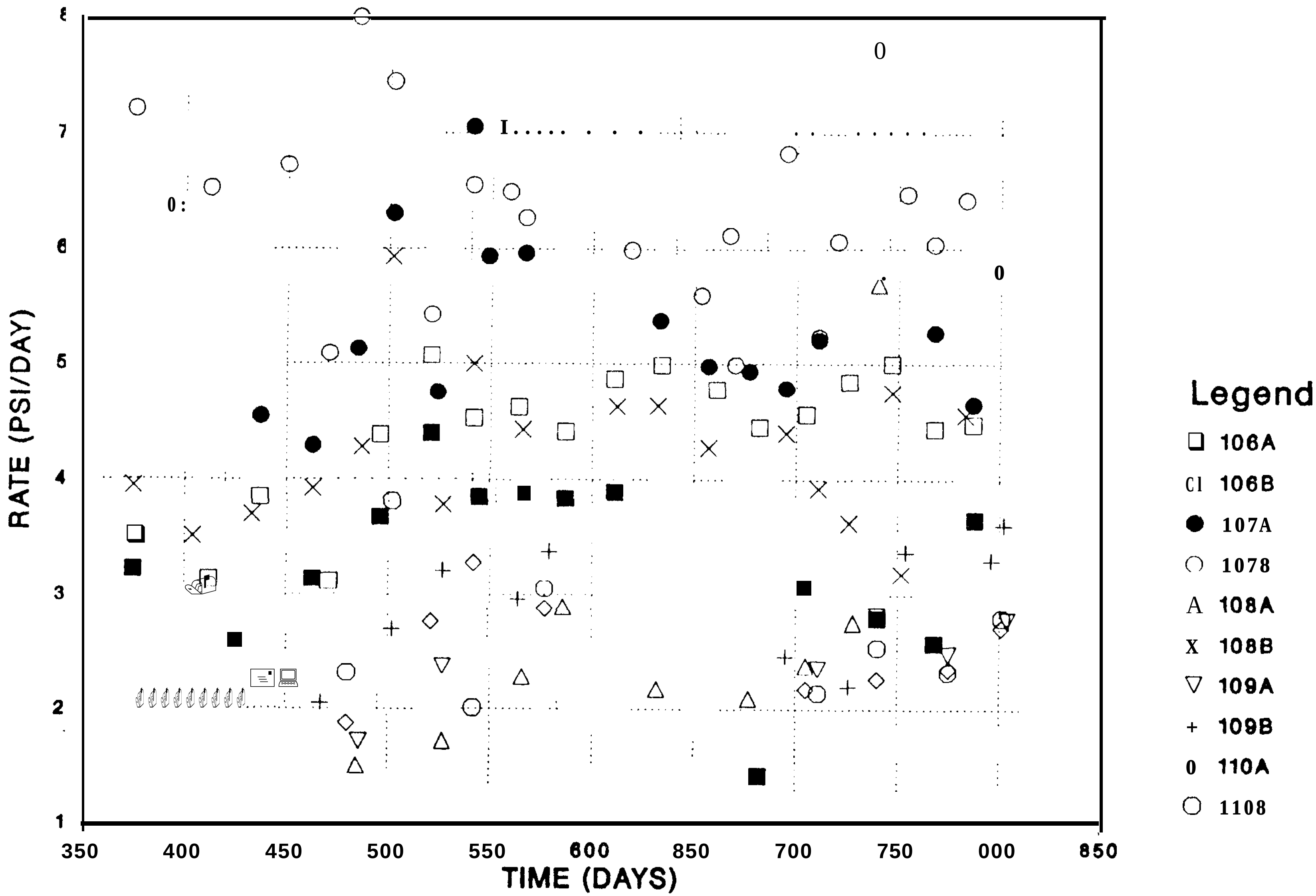
BIG HILL WELL PRESSURIZATION RATES



Appendix 9

Chemical Equilibrium Calculations to Determine Gas Intrusion into SPR Caverns

Chemical Equilibrum Calculations to Determine Gas Intrusion into SPR Caverns

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Introduction

Estimating past gas intrusion rates provides valuable information to the SPR that may be used to predict future intrusion rates and thereby aid in the decision of how frequently degassing should occur to maintain SPR's promised deliverability. Using compositional and GOR (gas-oil ratio) data from the Weatherly Laboratories Test Skid and gas-oil equilibrium data from the *Engineering Data Book* of the Gas Processors Suppliers Association, flash calculations were performed to determine the bubble points of 40 SPR caverns. After statistical analysis to ensure the validity of calculated bubble points, intrusion rates were calculated based upon the delivered temperature of the oil and storage time.

Flash Calculations

Flash calculations to determine the bubble point, or gas-oil equilibrium pressure, relied upon the gas-oil equilibrium ratio (K_i) given for different components in the Gas Processors Suppliers Association's *Engineering Data Book* [1]. Ki is the ratio of the mole fraction of the *ith* component in the vapor phase to the mole fraction of that component in the liquid phase:

$$K_i = \frac{y_i}{x_i} \tag{1}$$

The K-values of hydrogen sulfide, methane, ethane, propane, iso-butane, n-butane, iso-pentane, n-pentane, and hexane at different temperatures were read from convergence pressure charts. Because the K-charts are strongly pressure dependent, these numbers were then used to calculate less pressure dependent Henry's law constants for each component:

$$H_i = \frac{p_i}{x_i} \tag{2}$$

[1] *Engineering Data Book*, Gas Processors Suppliers Association, 1987, Section 25.

where H_i expresses the proportional relationship of the partial pressure of component *i* above a liquid to the mole fraction of component *i* in the liquid For the low pressures at which these flash calculations are performed, it is assumed that an ideal gas phase exists. Hence, the conversion of H_i to Ki is as follows:

$$y_i = \frac{p_i}{P}$$

$$K_i = \frac{y_i}{x_i} = \frac{p_i}{P \cdot x_i}$$

$$P \cdot K_i = \frac{p_i}{x_i} \rightarrow H_i = P \cdot K_i \qquad (3)$$

where P stands for total pressure. Equation (3) was then used to determine the H_i for each component. These Hi were found to be independent of pressure and dependent on temperature according to the following relationship:

$$\ln(H_i) = \frac{m_i}{T} + b_i \qquad (4)$$

where T is the absolute temperature and mi and b_i are constants as determined in Table 1. These equations were then used for all subsequent calculations of Hi. Individual plots of the thermal dependence of H_i are shown in Appendix 1.

Table 1

Component	m(i)	b(i)
Hydrogen Sulfide	-1769.44	9.35
Oxygen	131.782	8.778
Nitrogen	-953.4	10.87
Carbon Dioxide	-2162.04	8.26
Methane	-892.71	9.56
Ethane	-2717.97	11.15
Propane	-3408.42	11.14
Iso-butane	-4302.59	11.86
N-butane	-4585	12.01
Iso-pentane	-5274.77	12.33
N-pentane	-5521.44	12.54
Hexane	-6701.28	13.5

Exceptions to this method were carbon dioxide, oxygen and heptanes plus. The Henry's law constant for CO_2 were determined from the relationship $(H_1 * H_2)^{1/2}$ as recommended in *the Engineering Data Book. The* Henry's law constant for oxygen was determined from the Zanker correlation[2]. As all components heavier than hexane were taken into account by one measurement, it was not possible to apply specific Ki and Hi values to any of these contributors to the flash gas. However, the contribution of these "heavies" to the bubble point is minimal, usually on the order of 2-3%. Therefore, the GOR was used to estimate the impact of the heptanes plus fraction.

Once K_i and Hi had been satisfactorily determined, vapor compositional data and GOR information from the Weatherly Test Skid were used to calculate feed composition of the oil using the relationship:

$$F \cdot z_i = L \cdot x_i + G \cdot y_i \tag{5}$$

where F represents moles of feed, L moles of Liquid, G moles of gas, z_i mole fraction of component i in the feed, yi mole fraction of i in the liquid, and xi mole fraction of i in the gas. Manipulating this equation to solve for z_i, and using the relationship between x_i and y_i given by Ki, one obtains the formula:

$$z_i = y_i\left(\frac{1-\frac{G}{F}}{K_i} + \frac{G}{F}\right) \tag{6}$$

G/F is obtained by using the measured GOR, molecular weight, and specific gravity of a sample.

For each cavern, the Weatherly Skid was used to perform a number of tests to deterrnine the composition of the evolved gas at various temperatures and pressures; a bubble point reading was also usually made for two temperatures (often 100°F and 130°F). For this analysis, vapor phase compositional data was used to determine the feed composition (z_i) for each test using equation (6). An average z_i was then calculated for each cavern, and from this average the bubble point was determined using the formula:

$$BP = \sum H_i \cdot avg(z_i) \tag{7}$$

To validate the calculated bubble point, two methods were used: the yi for each test made on a cavern were recalculated from the average zi, usually showing error of less than 10%, and a series of comparisons were compiled for each dome. The difference between calculated and measured bubble point (ΔBP) was plotted against separator temperature, oil temperature, measured bubble point, hydrogen sulfide content, carbon dioxide content, nitrogen content, and methane content. No discernible trends showed up on any of these plots, implying that all errors were due to random occurrences. (Appendix 2) In most cases error fell within a reasonable range, lending credence not only to the calculations, but to the Test Skid data

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[2]Zanker, A "Inorganic Gases in Petroleum," *Hydrocarbon Processing*, May 1977. p.255

Gas Intrusion Calculations

In order to determine the rate of gas intrusion into a cavern, measurements of the increase in a gas dependent property such as the bubble point must made. **At the time** of receipt, the oil is assumed to be "dead" (no gas content), meaning that at the delivery temperature of 80°F the oil had a bubble point of 1 atm (14.7 psi). The intrusion rate **is** determined by finding the increase in bubble point at 80°F from the time of receipt to the time of sampling. Thus, the Henry's law constants determined above were calculated for an 80°F delivery temperamre, and bubble points were then determined for each available cavern at 80°F. (Tables 2, 3 &4) In these tables, some small but negative intrusion rates are observed, and are believed to provide and indication of data scatter.

Table 2

Site	Cavern #	Date of Oil Fill	Date of Sample	Gas Intrusion psi/year @80°F
West Hackberry	6	Nov-77	Mar-94	0.03
	9	Nov-78	Mar-94	-0.06
	11	Oct-77	Mar-94	-0.05
	102	Sep-83	Jun-93	-0.01
	103	Sep-82	Mar-94	0.02
	104	Oct-82	Mar-94	-0.03
	105	Nov-82	Mar-94	0.04
	106	Nov-85	Mar-94	0.00
	107	Jul-83	Mar-94	-0.05
	108	Jun-83	Mar-94	-0.05
	109	Nov-86	Jun-93	-0.18
	110	Dec-83	Mar-94	-0.07
	111	Mar-87	Mar-94	0.07
	112	Jun-85	Mar-94	-0.04
	113	Jul-84	Mar-94	-0.02
	114	Oct-84	Mar-94	-0.04
	115	Aug-86	Mar-94	-0.09
	116	Mar-85	Jun-93	-0.18
	117	Jul-88	Aug-93	0.10

Table 3

Site	Cavern #	Date of Oil Fill	Date of Sample	Gas Intrusion psi/year @80°F
Bryan Mound	2a	Dec-77	Apr-93	0.36
	4a	Dec-77	Jan-94	0.01
	5a	Oct-87	Sep-93	0.02
	101	Aug-83	Feb-94	0.83
	102	Oct-83	Feb-94	0.11
	103	Mar-83	Sep-93	1.94
	104	Apr-82	Feb-94	0.12
	105	Apr-82	Feb-94	0.12
	107	Feb-82	Feb-94	0.12
	109	Aug-82	Feb-94	0.62
	110	Dec-81	Feb-94	-0.05
	111	Jul-84	Sep-93	1.89
	112	Jun-84	Oct-93	2.22
	114	Jul-87	Jan-94	0.57
	115	Jan-87	Feb-94	0.11

Table 4

Site	Cavern #	Date of Oil Fill	Date of Sample	Gas Intrusion psi/year @80°F
Bayou Choctaw	15	Jan-78	Feb-94	-0.08
	17	Apr-87	Feb-94	0.14
	18	Dec-78	Feb-94	0.05
	19	Nov-78	Feb-94	-0.07
	20	May-81	Mar-94	0.14
	101	Oct-88	Feb-94	0.22

Table 5

Site	Cavern #	Date of Oil Fill	Date of Sample	Gas Intrusion psi/year @80°F
Big Hill	101	Feb-89	Apr-94	-0.24
	102	Am-89	Apr-94	-0.13
	103	May-89	Apr-94	0.12
	104	Mar-89	Apr-94	-0.07
	105	act-88	Apr-94	0.25
	106	Mar-89	Apr-94	1.85*
	107	Oct-88	Am-94	0.72*
	110	Nov-88	Apr-94	0.25
	111	Apr-90	Apr-93	14.45**
	113	Mar-90	Apr-94	7.27**
	114	Apr-90	Apr-94	8.74**

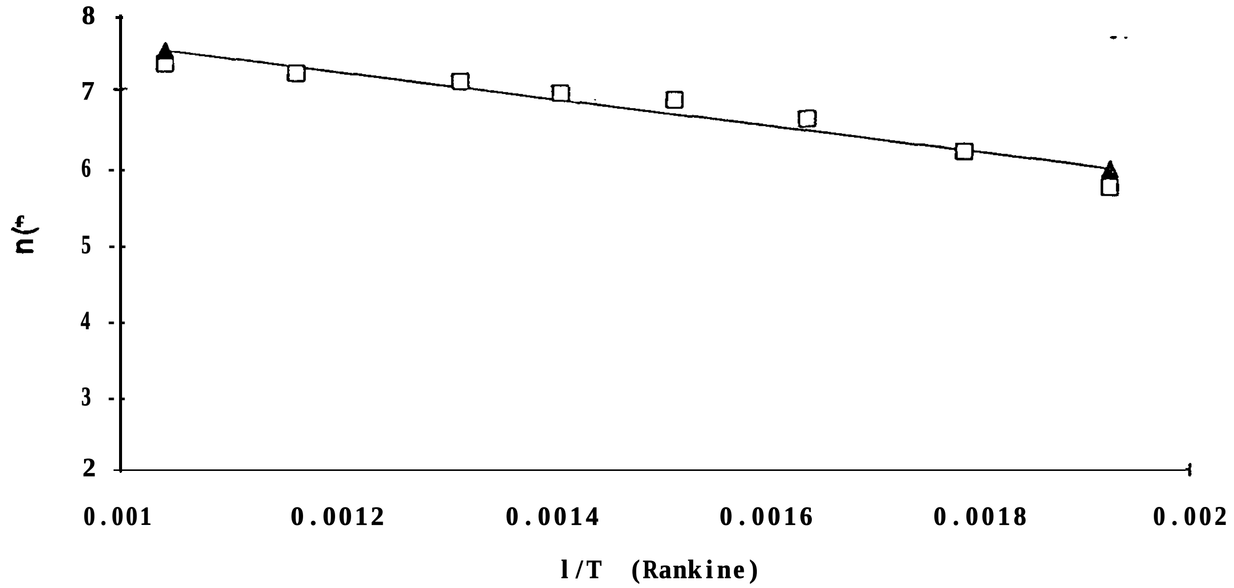
*oil shipped from Sulfur Mines

**small quantity of stored oil exaggerates intrusion rates

Conclusions

The GORs and compositional data obtained from the Weatherly skid provides an internally consistent set of data for the determination of bubble point. The average difference between the computed and measured bubble points is -0.35 for West Hackberry, -0.46 for Bryan Mound, -0.15 for Bayou Choctaw, and -3.01 for Big Hill. The standard deviation around the mean for each site is 0.73 for West Hackberry, 1.20 for Bryan Mound, 0.46 for Bayou Choctaw, and 5.19 for Big Hill.

Hydrogen Sulfide



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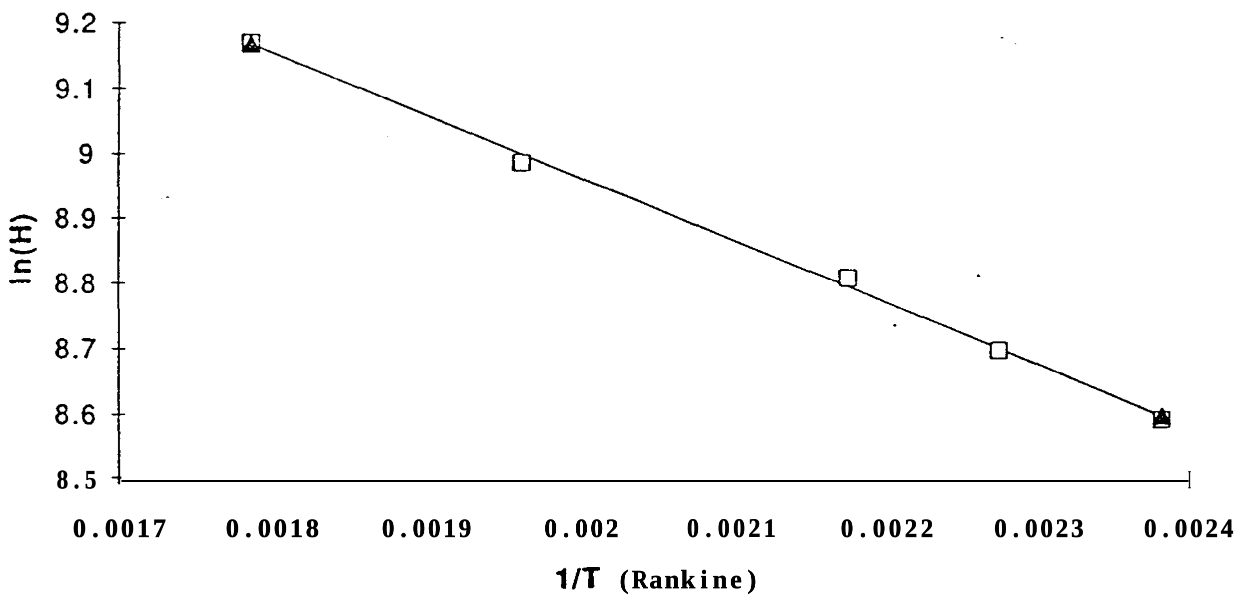

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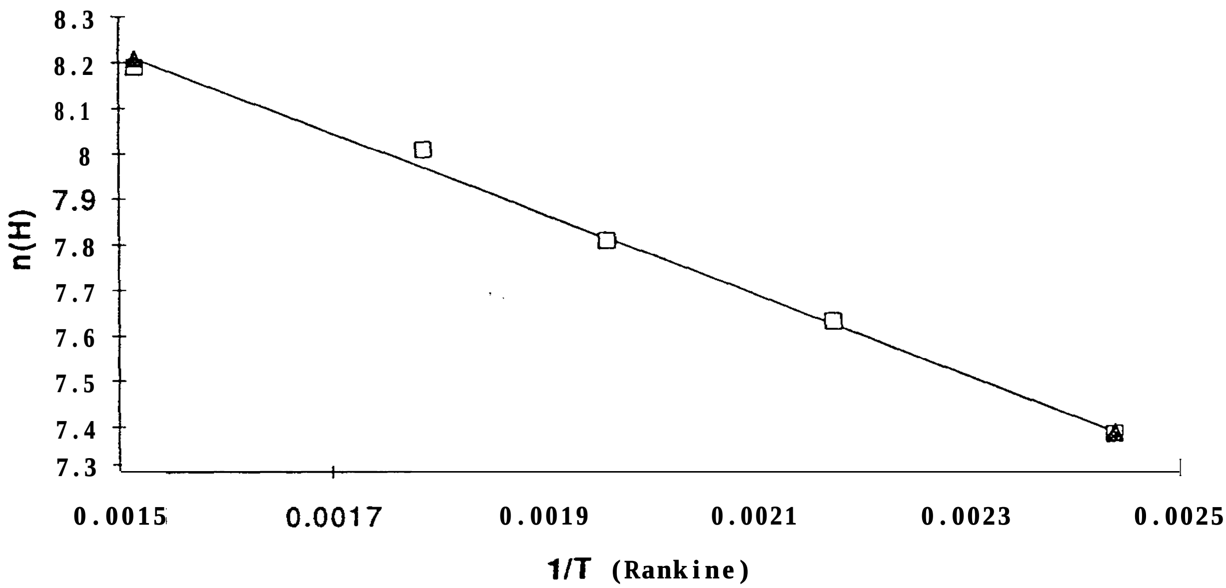

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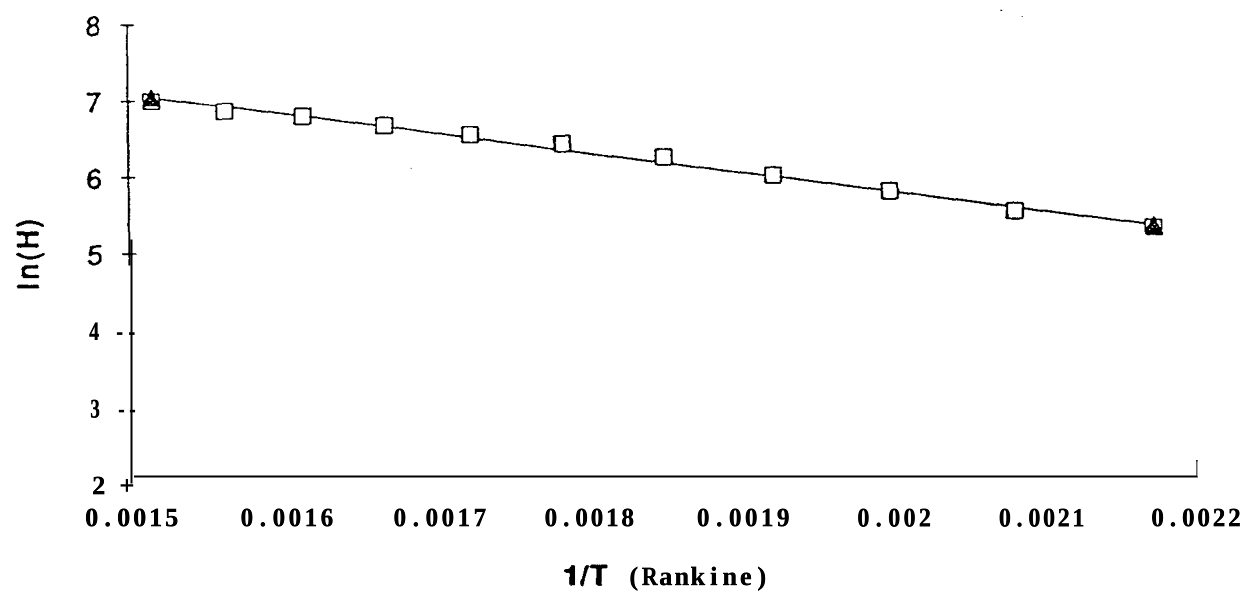

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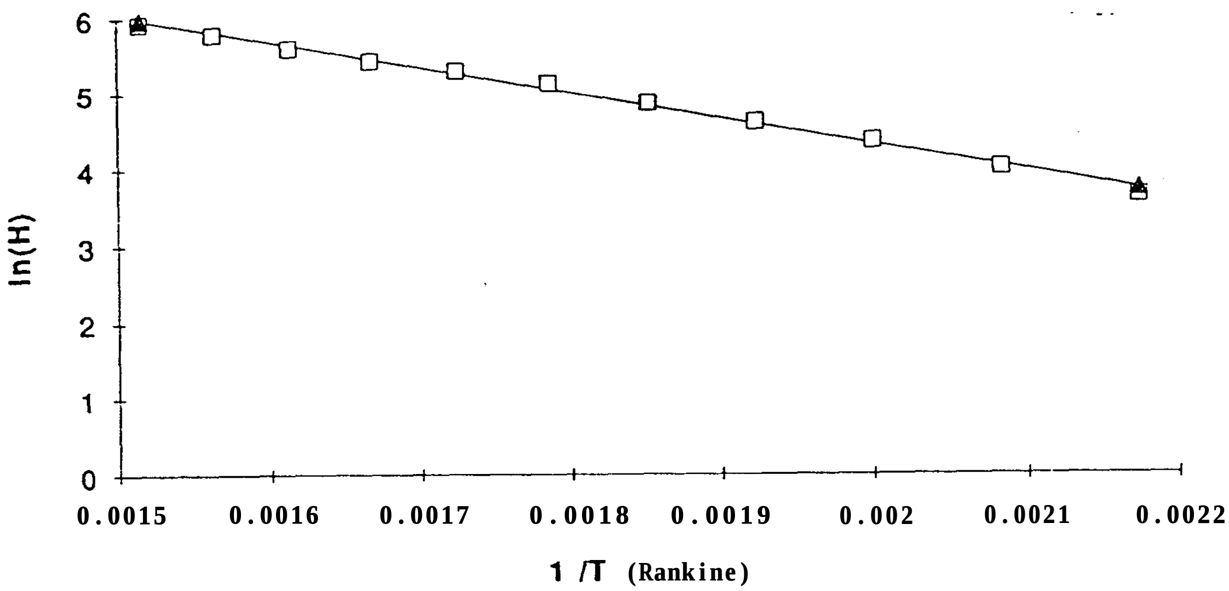

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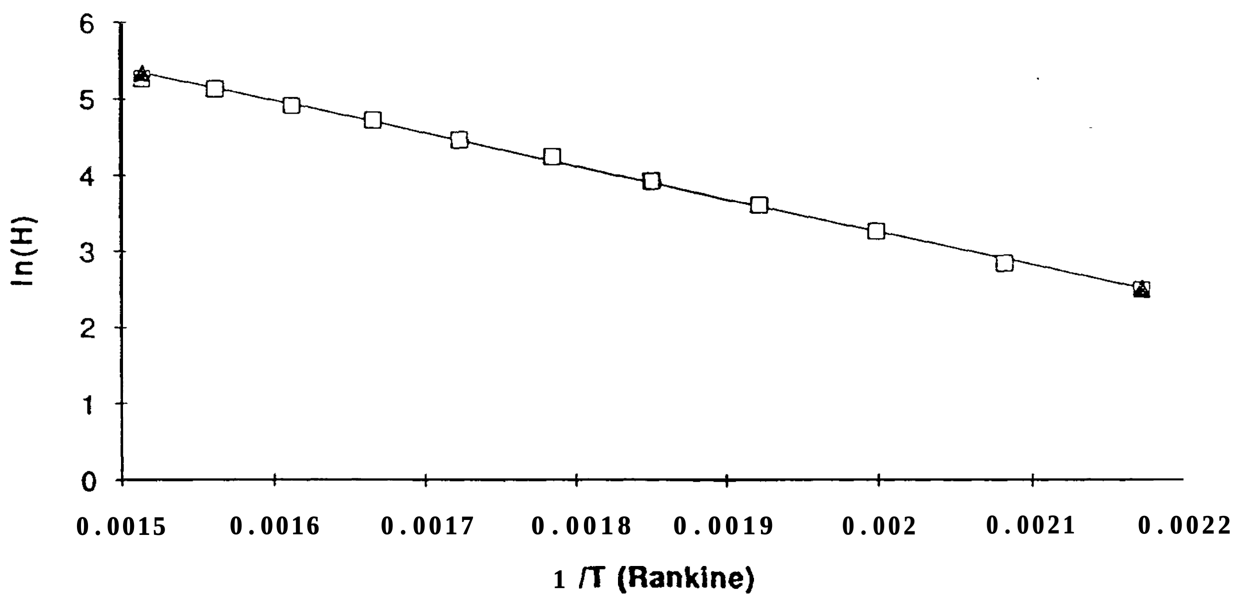

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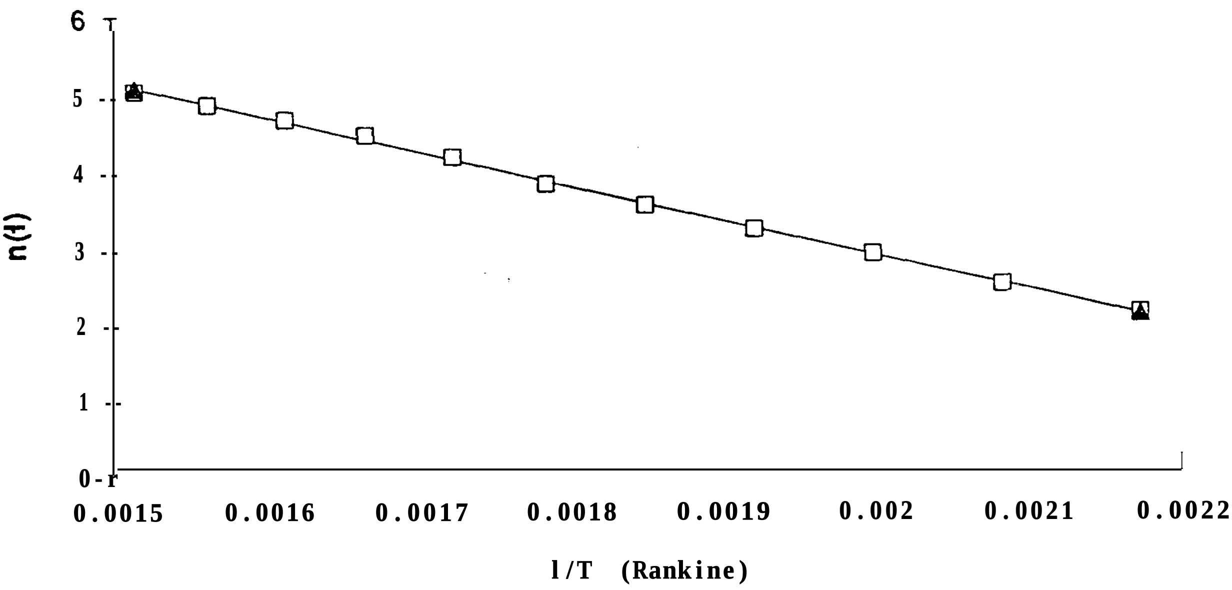

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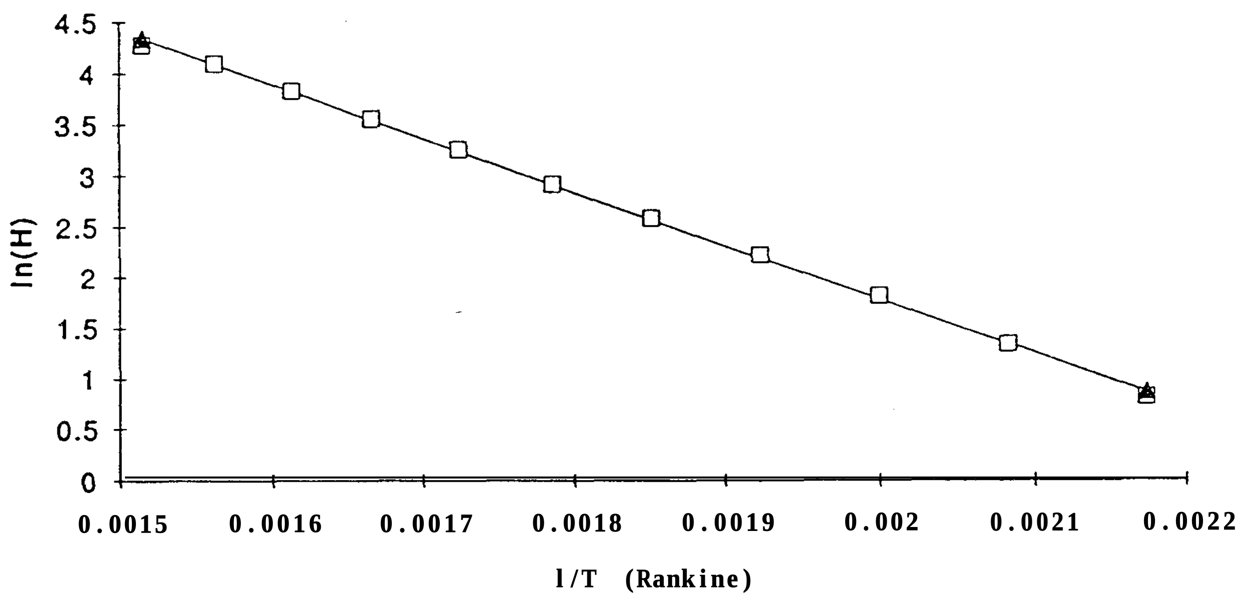

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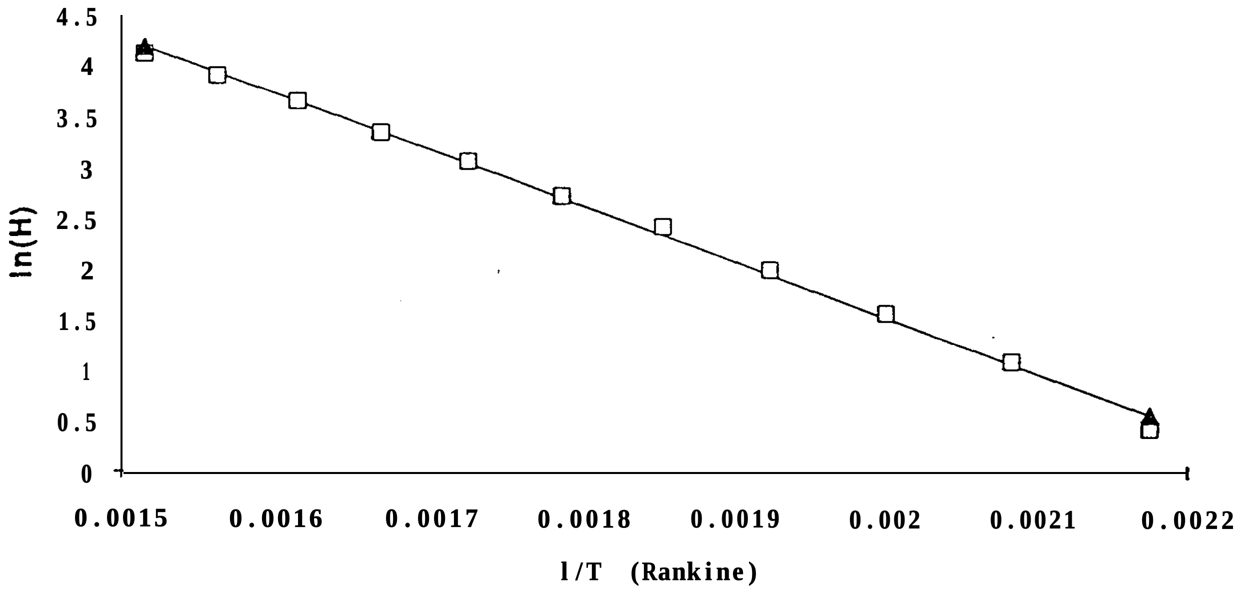

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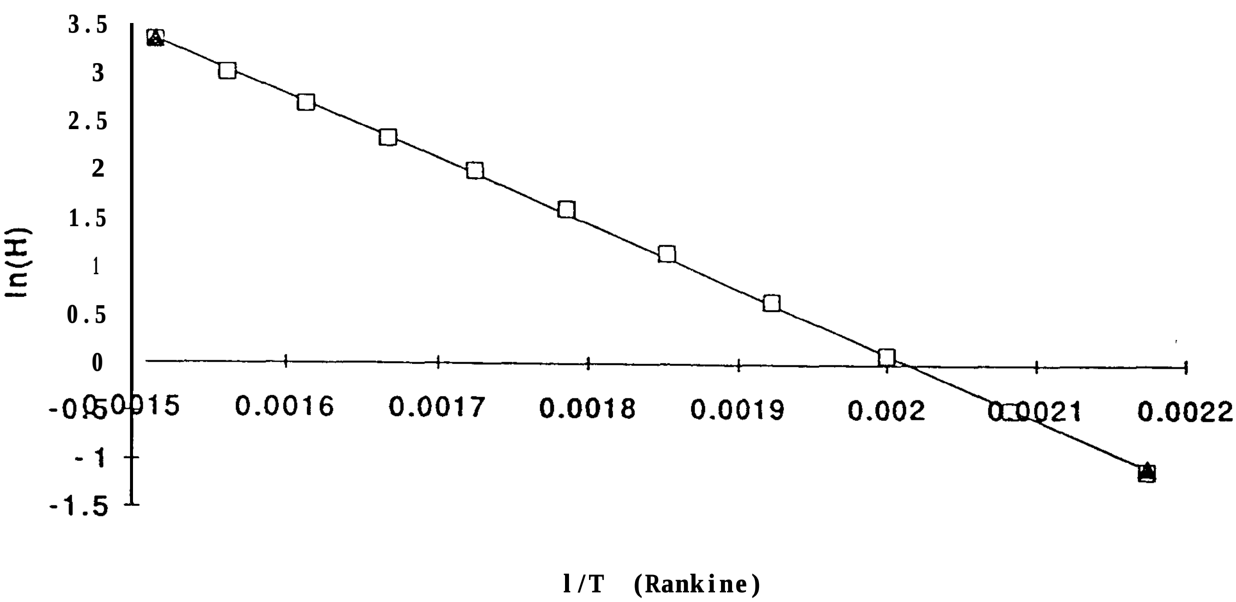

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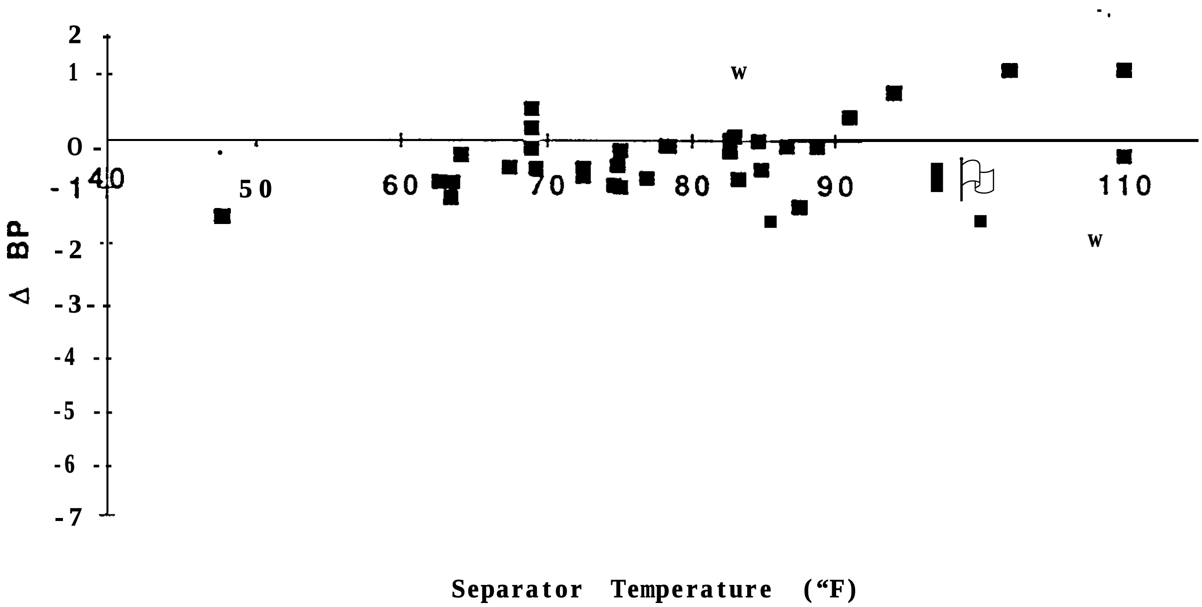

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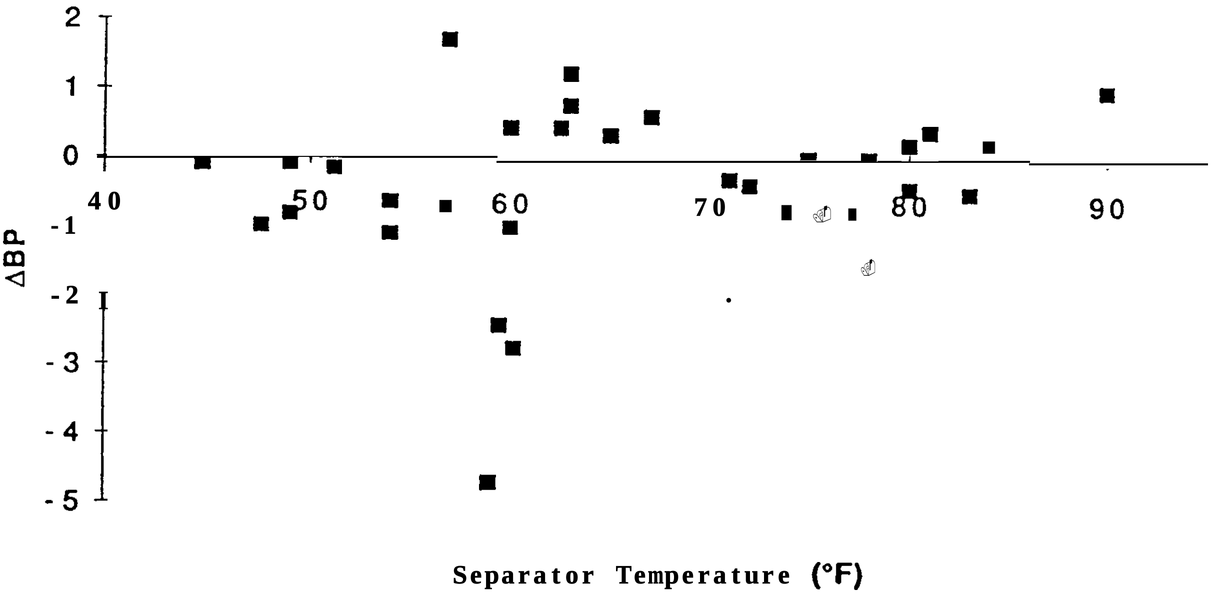
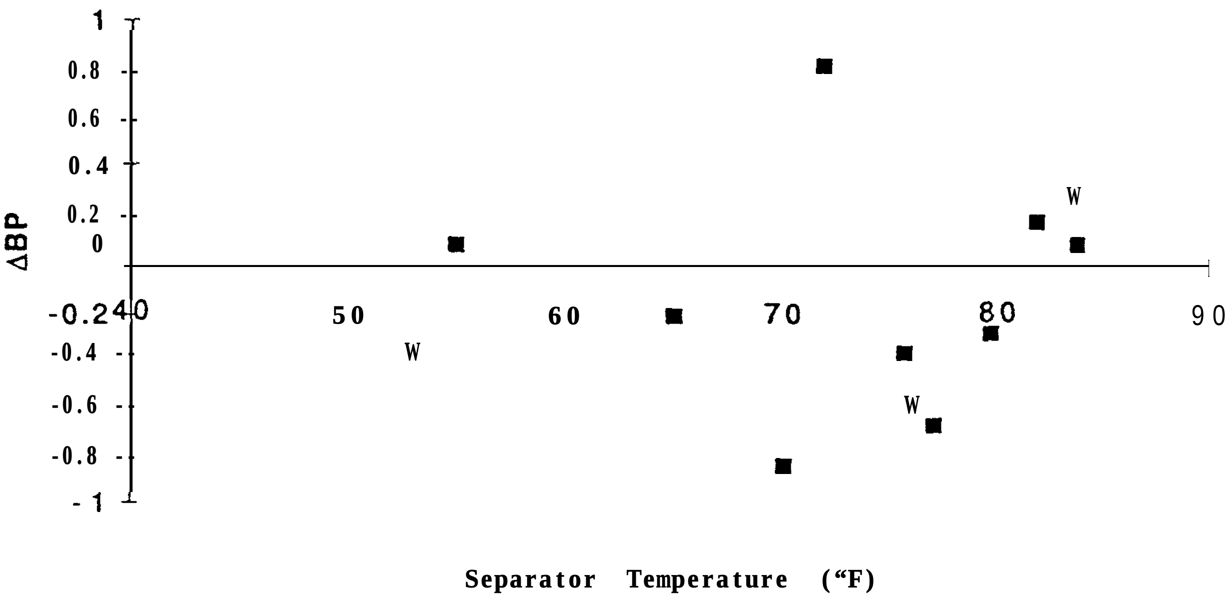


Bayou Choctaw



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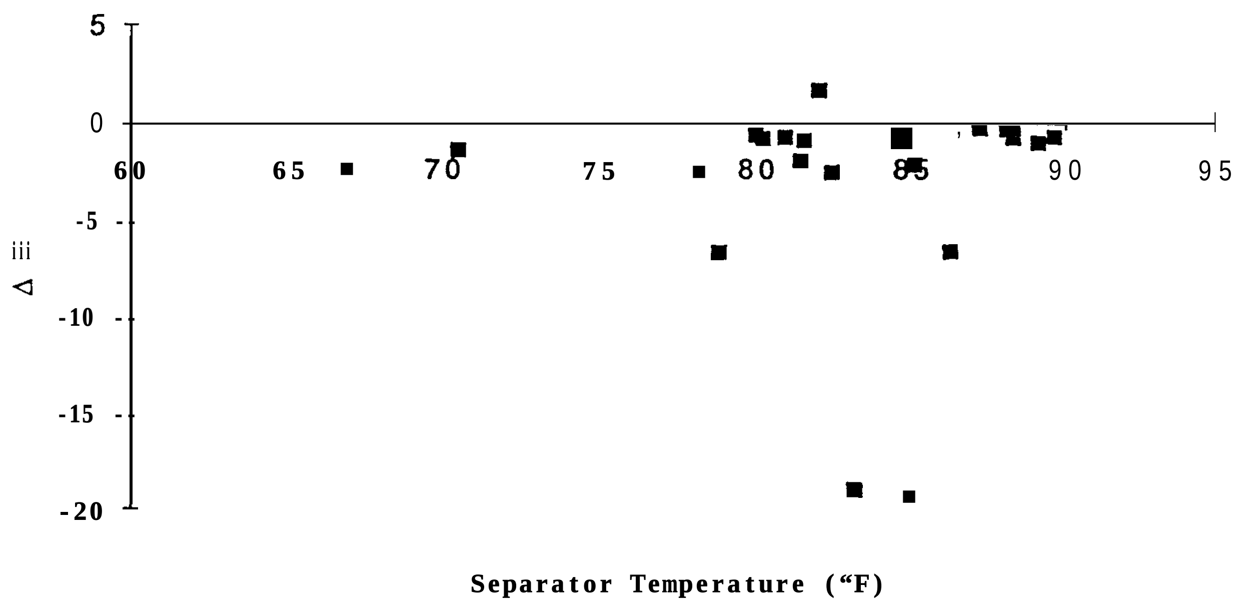

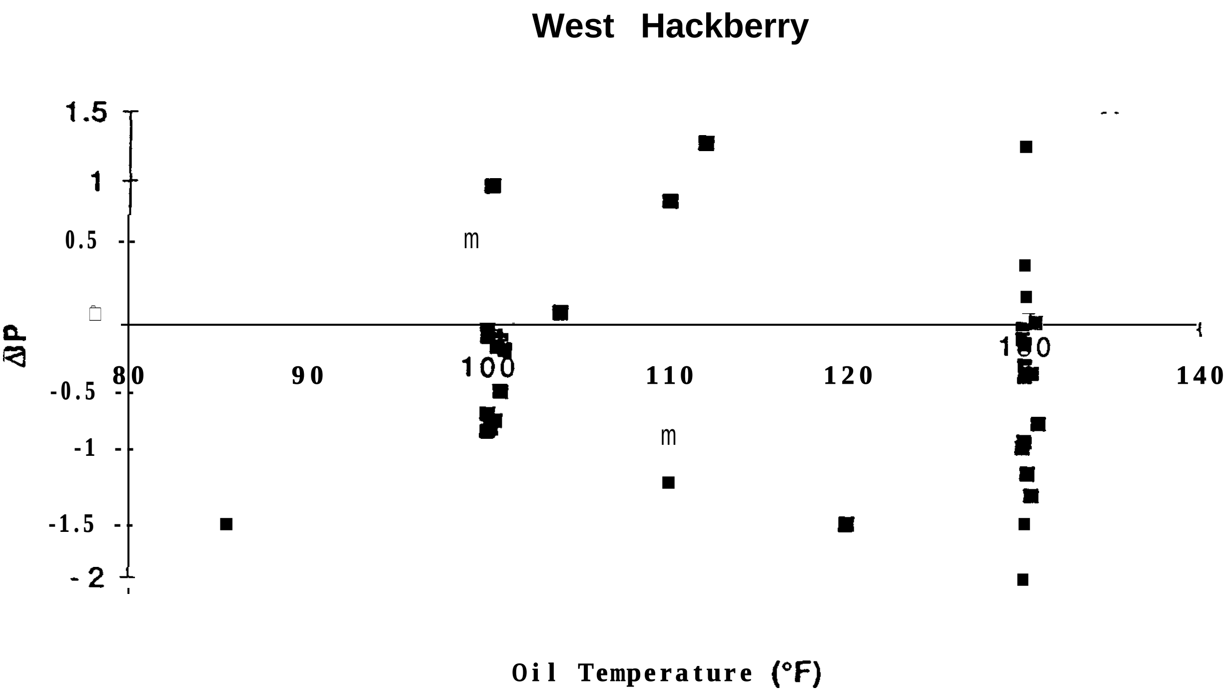
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1
0.5
-0.5
-1
-1.5
-2
ΔP
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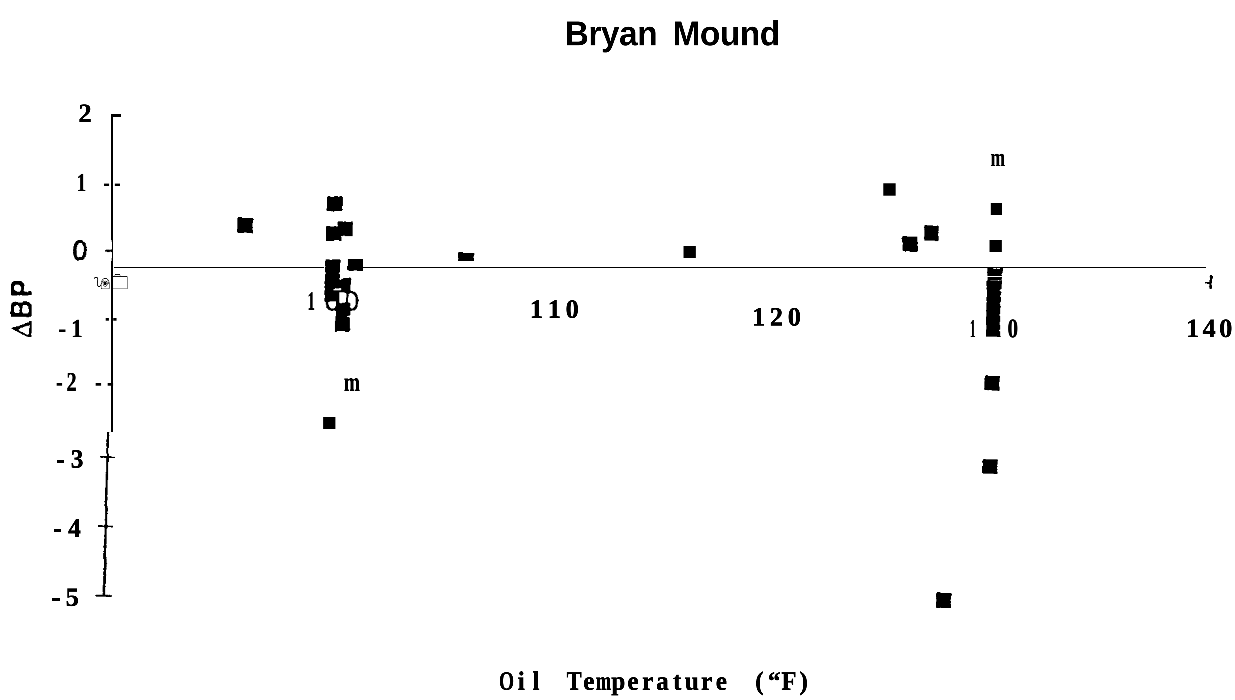
90
100
110
120
130
140
Oil Temperature (°F)


Bryan Mound
2
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-4
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ΔBP
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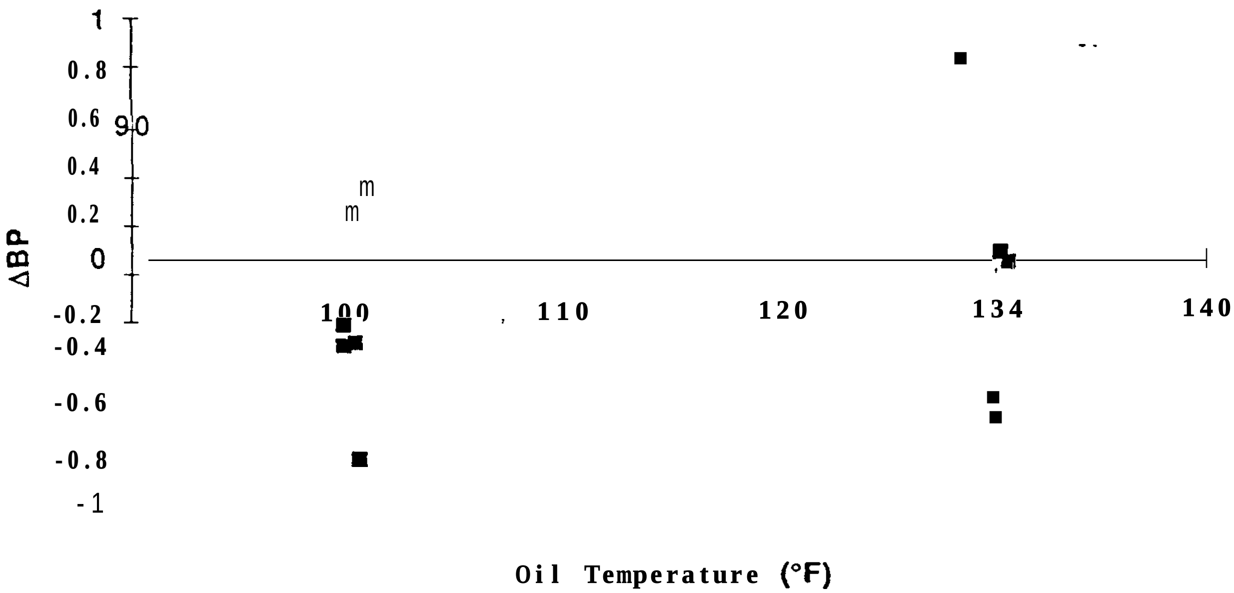
110
120
130
140
Oil Temperature (°F)

Bayou Choctaw



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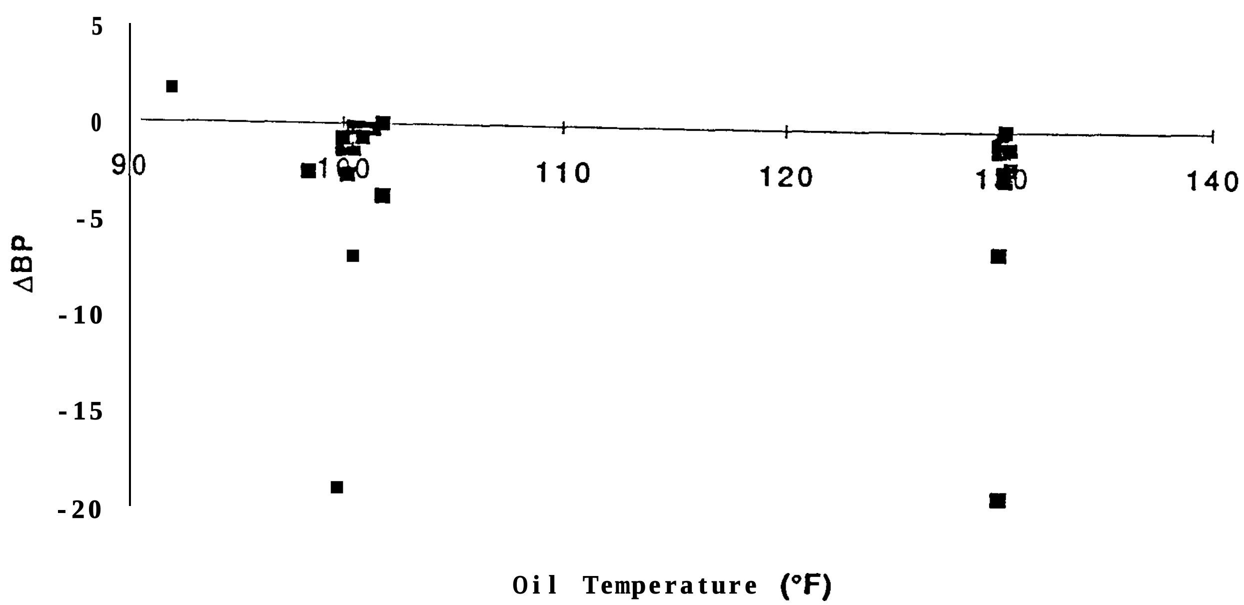

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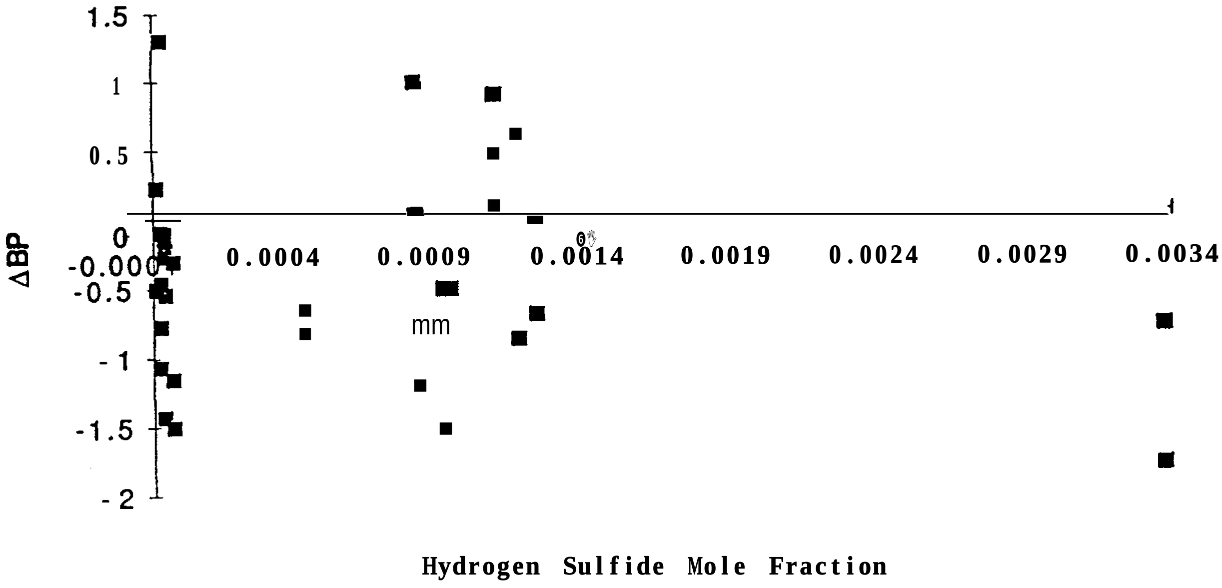

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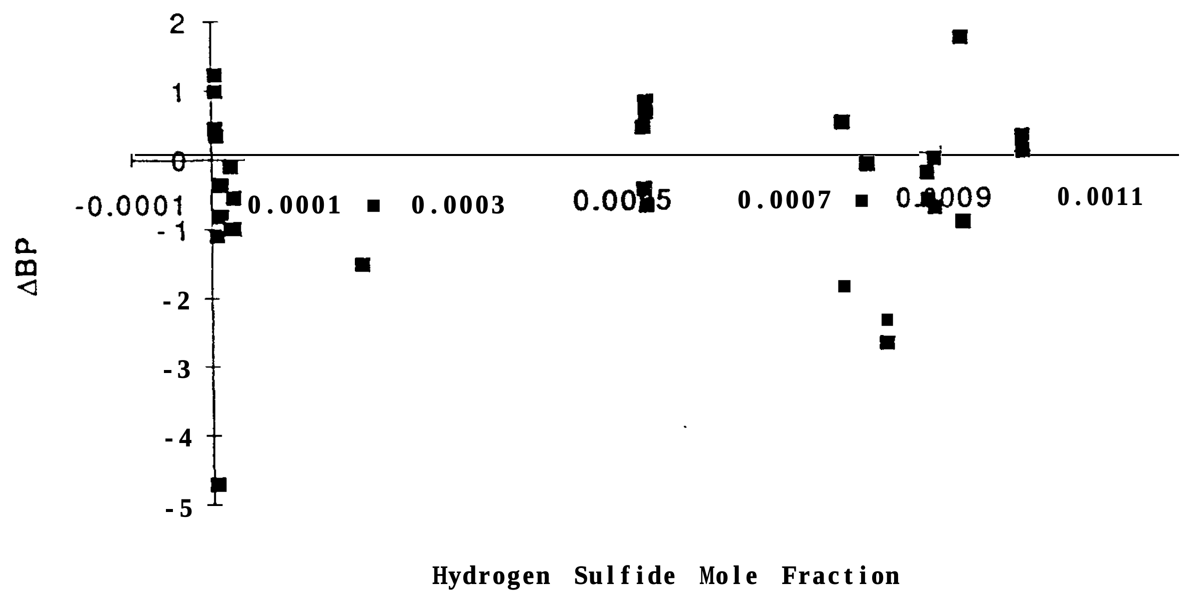

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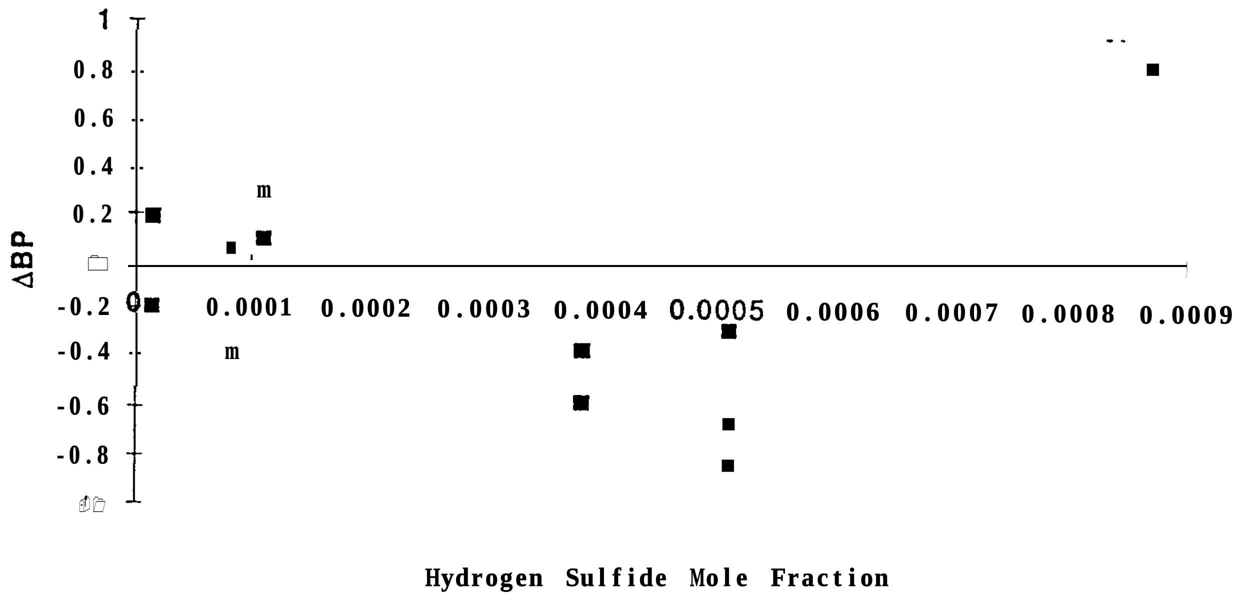

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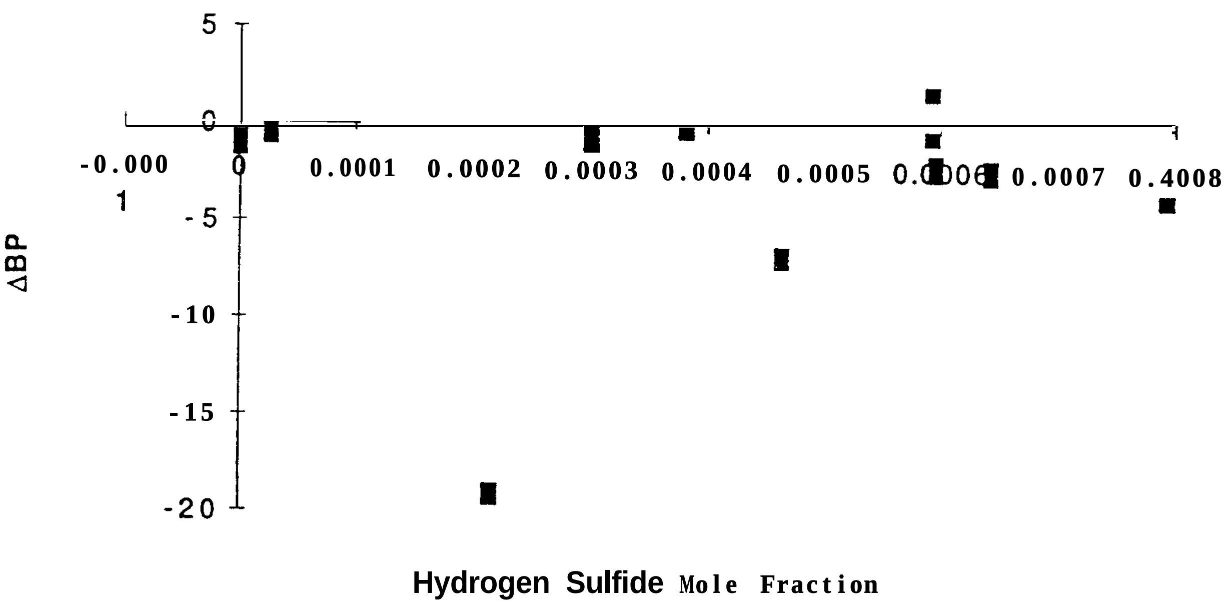

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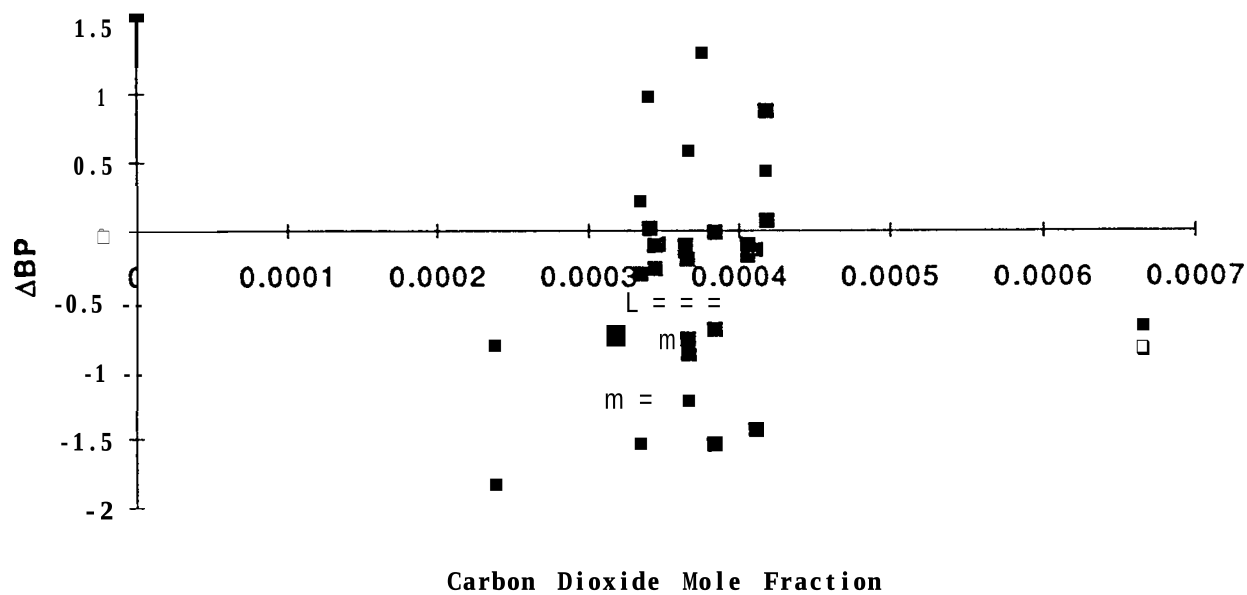

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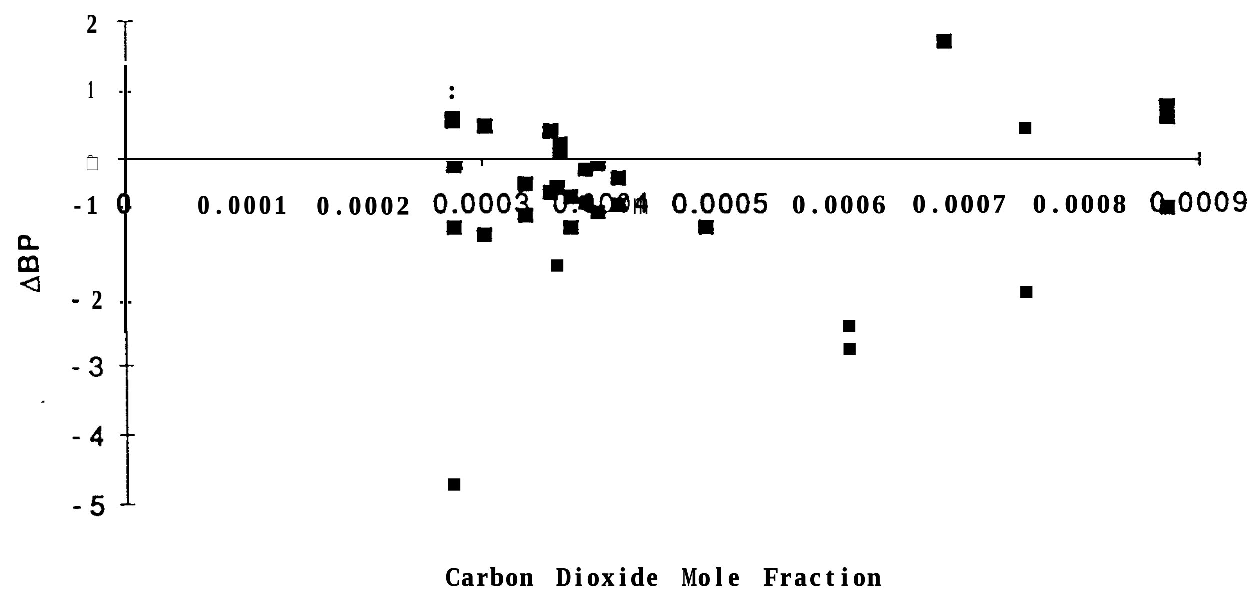

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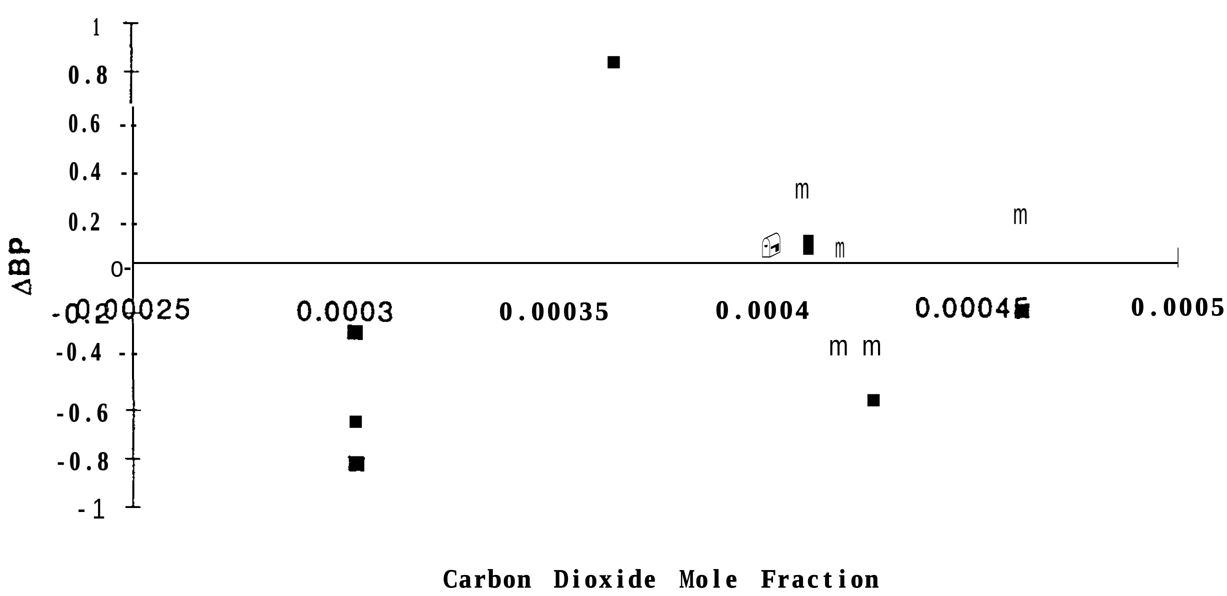

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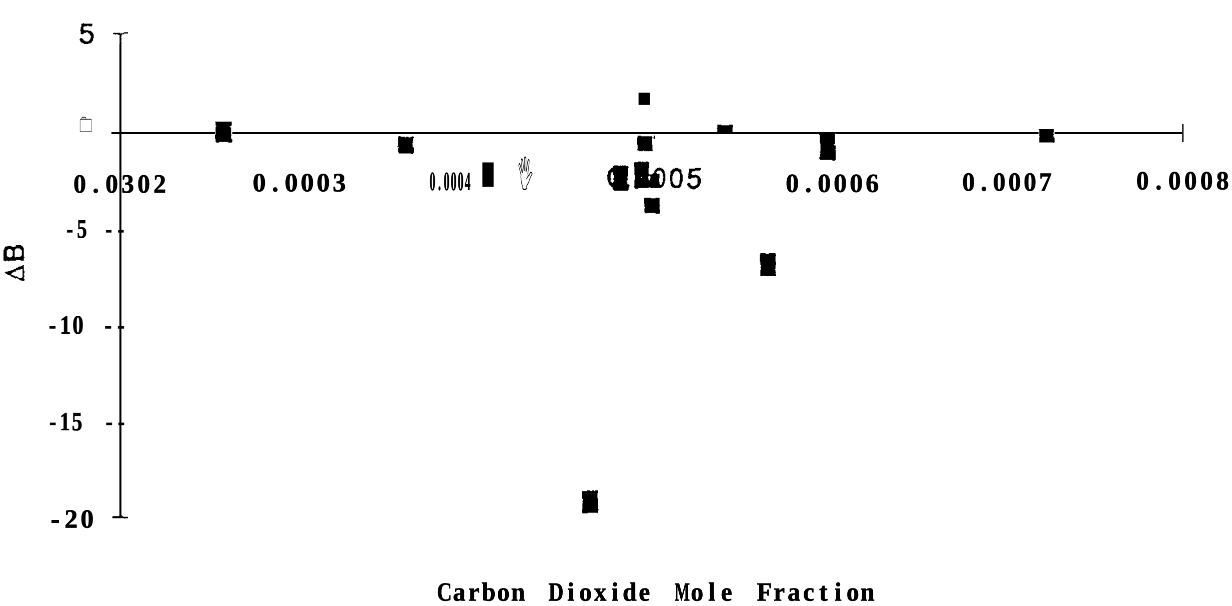

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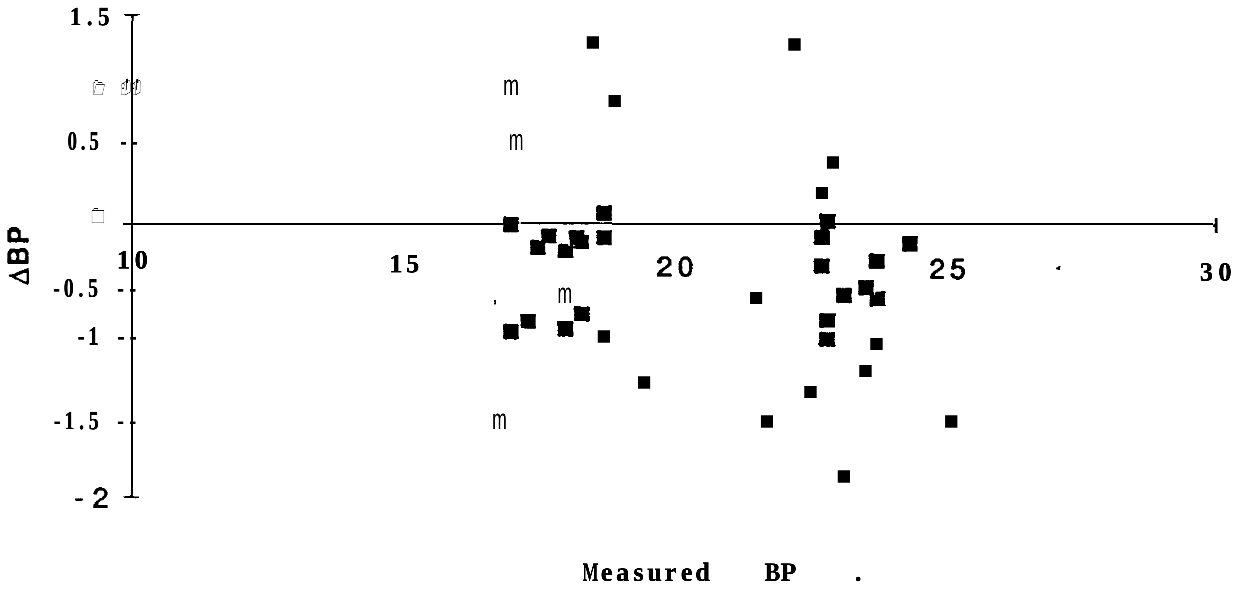

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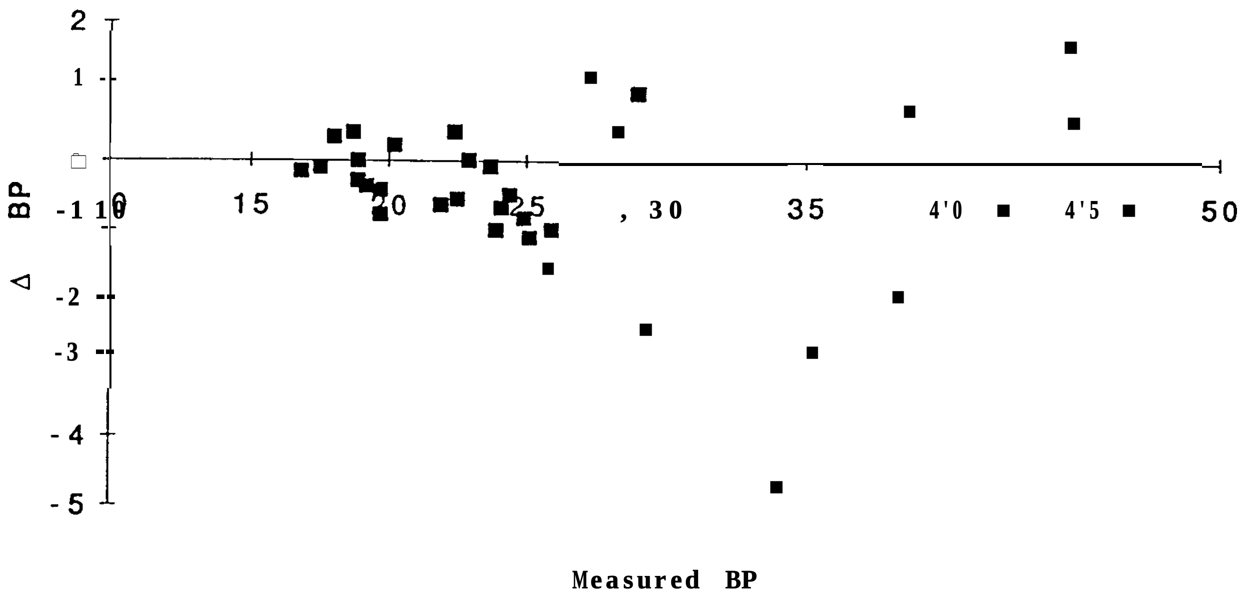

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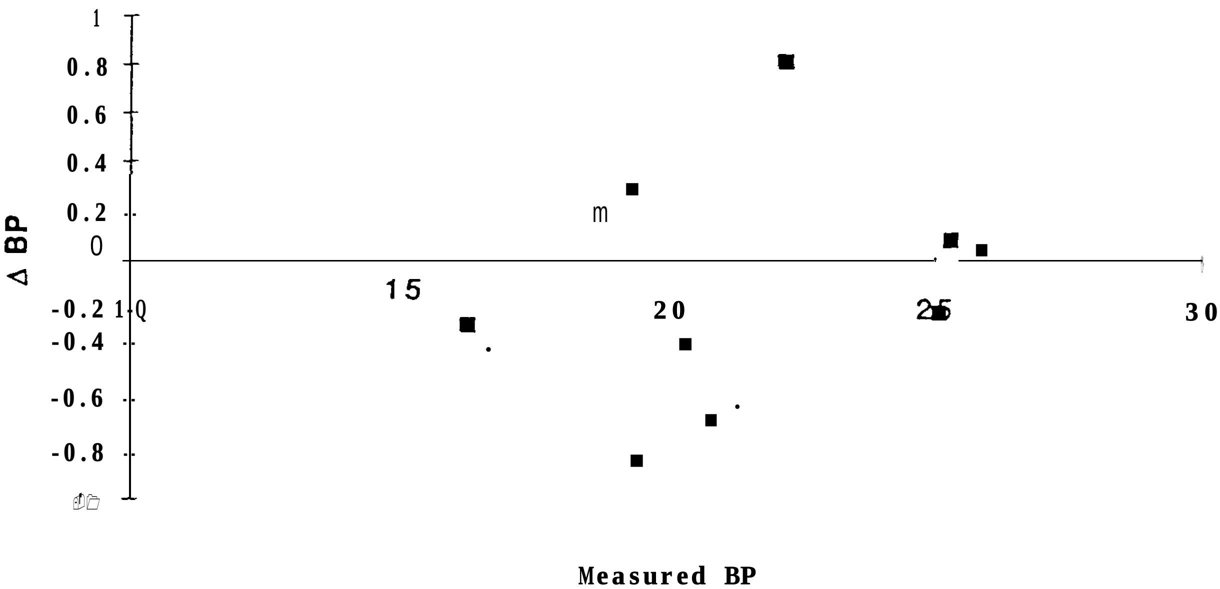

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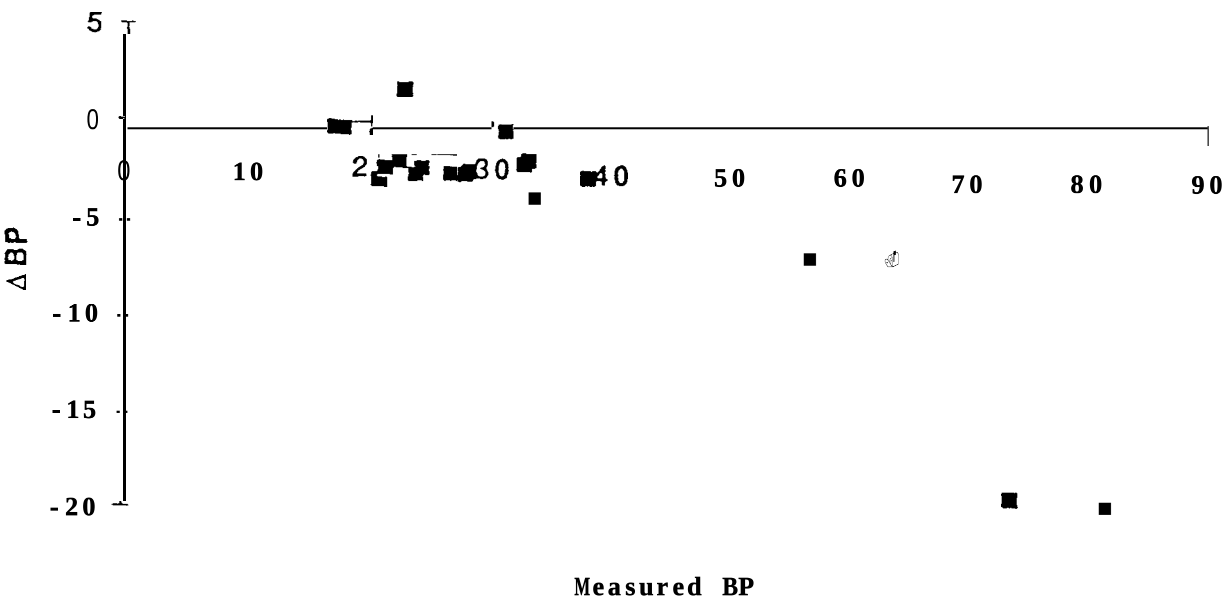

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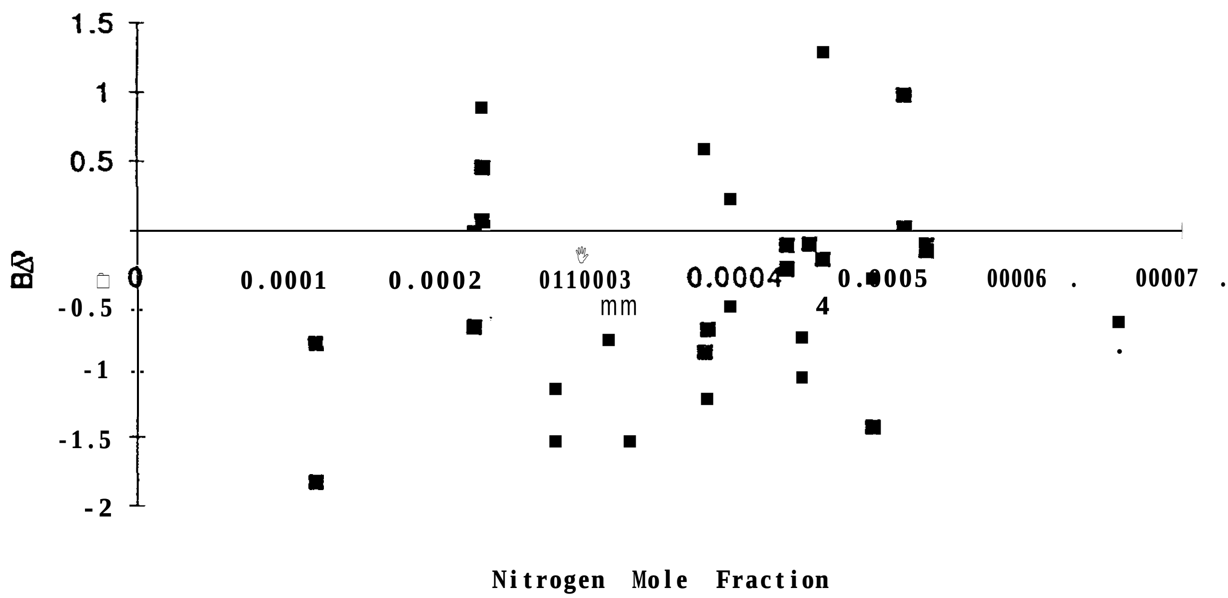

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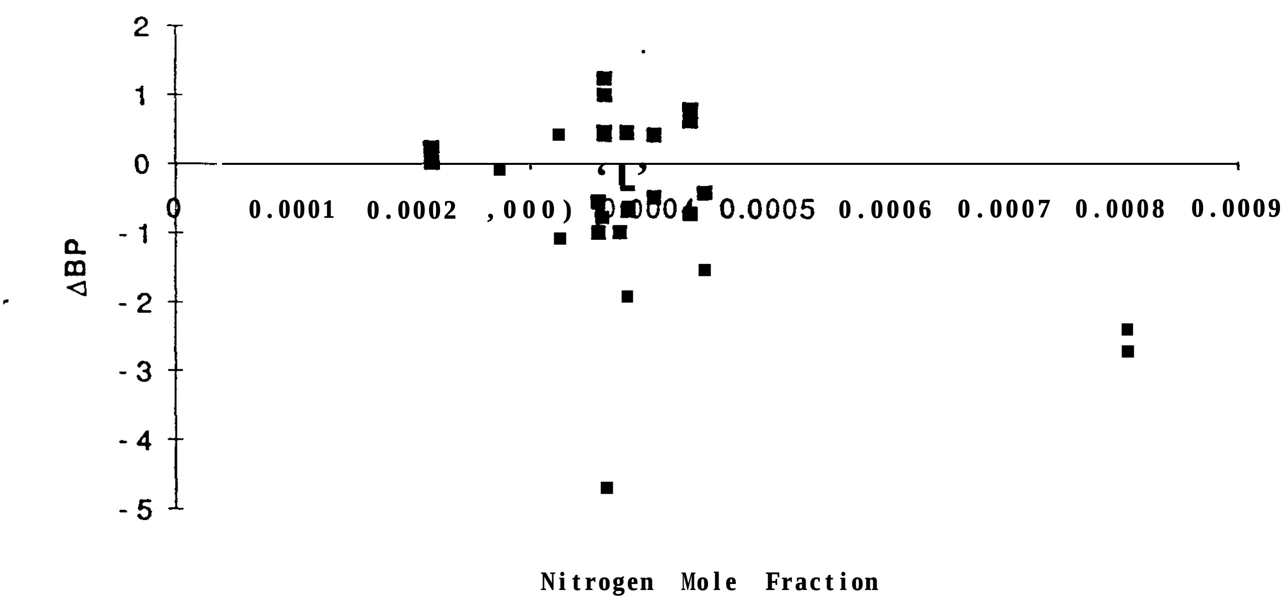

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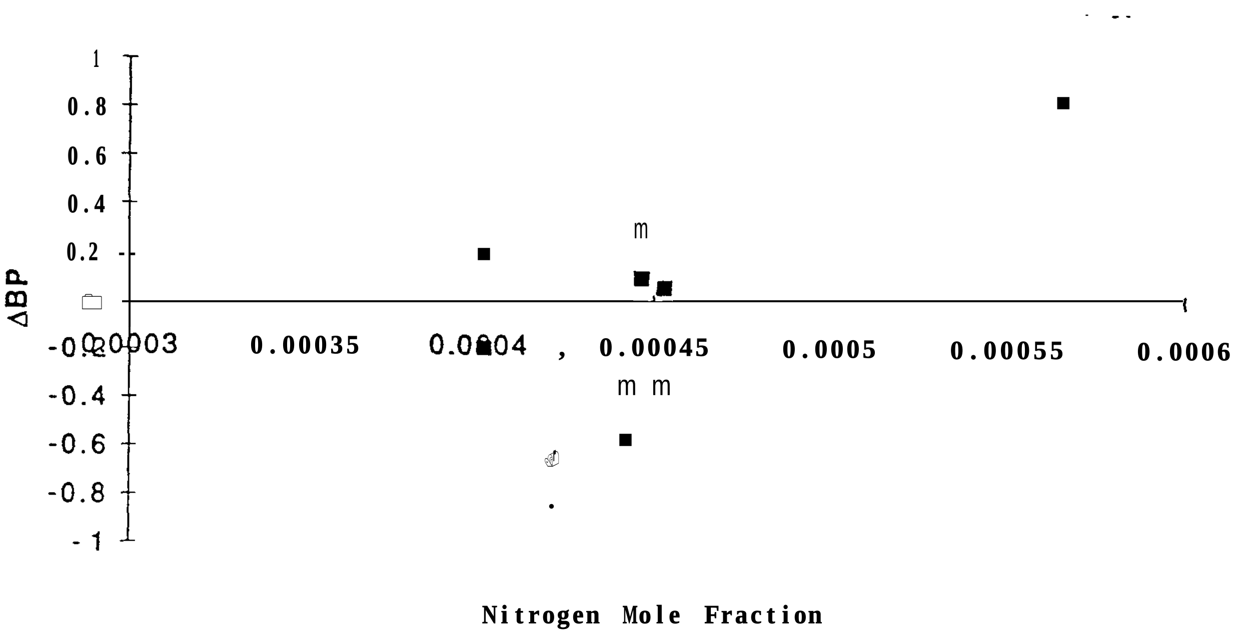

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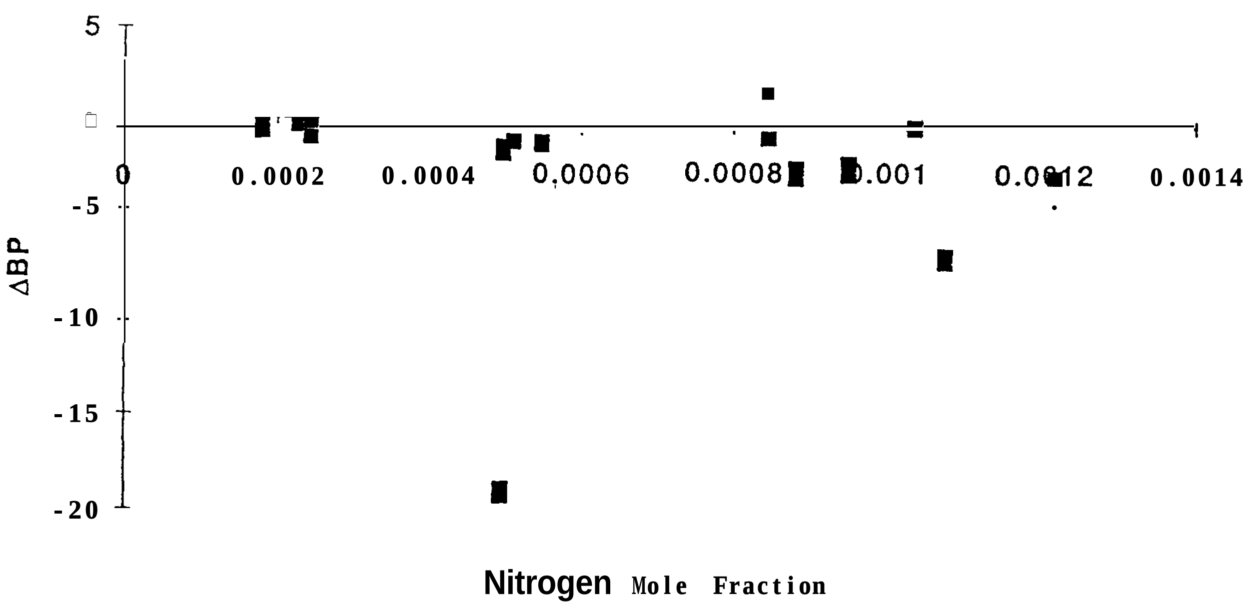

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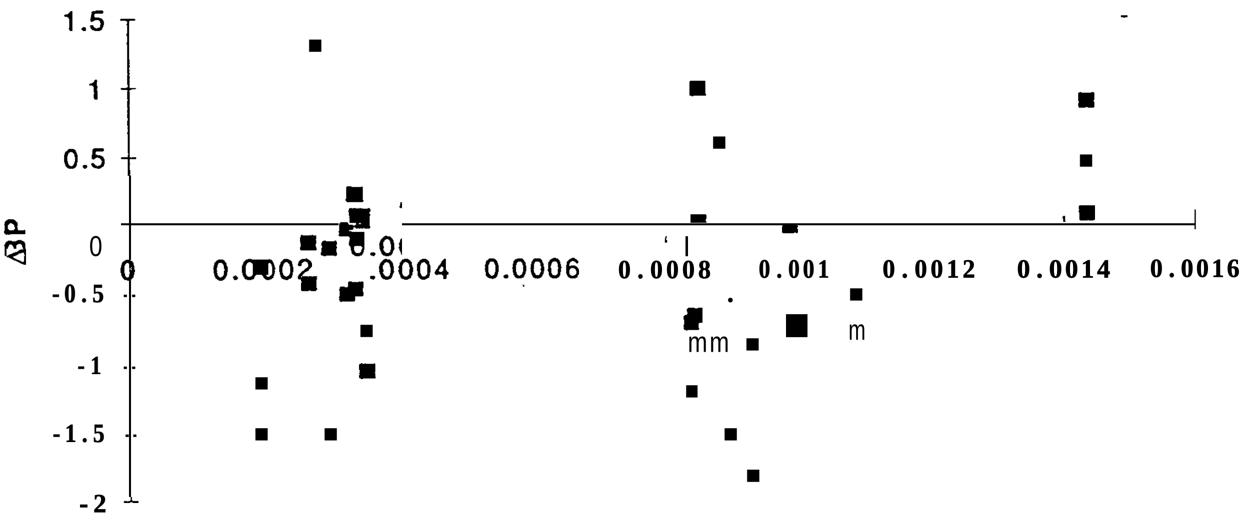

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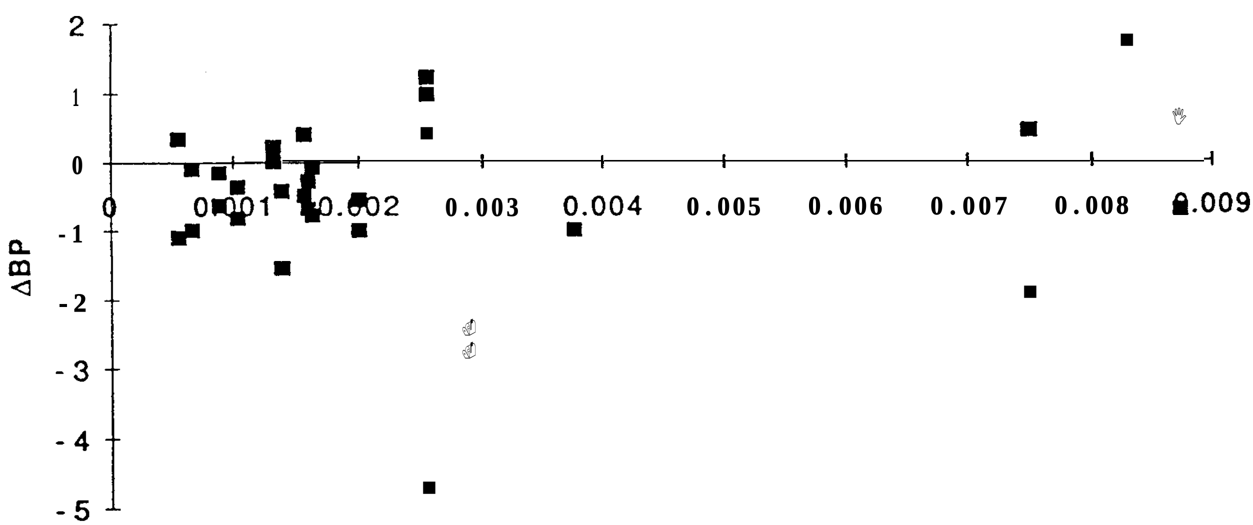

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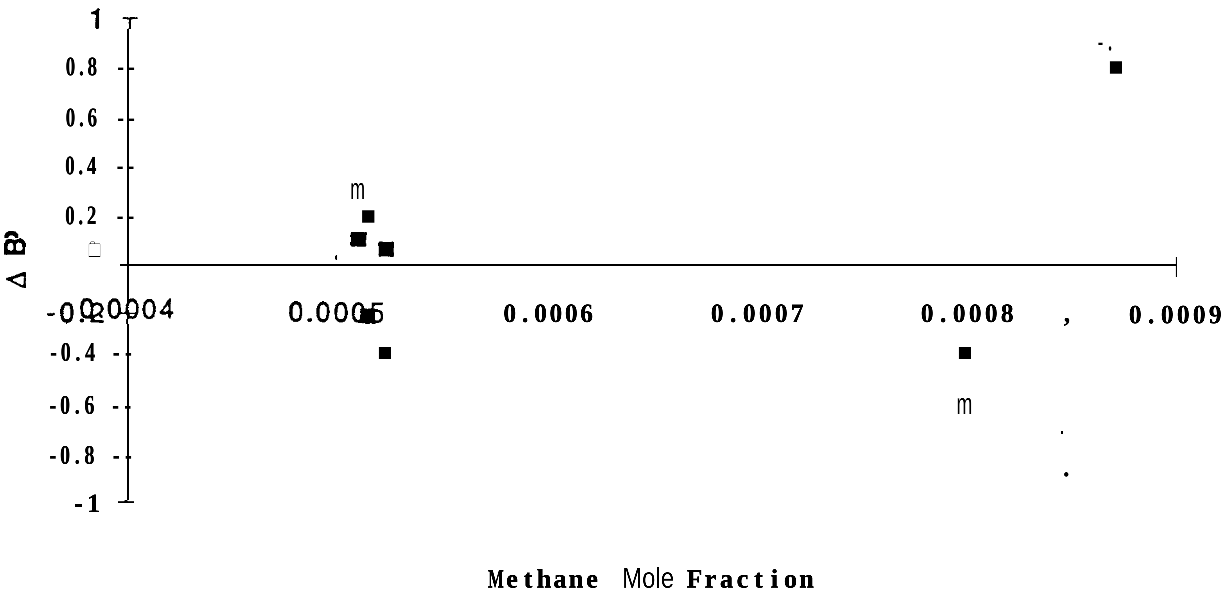

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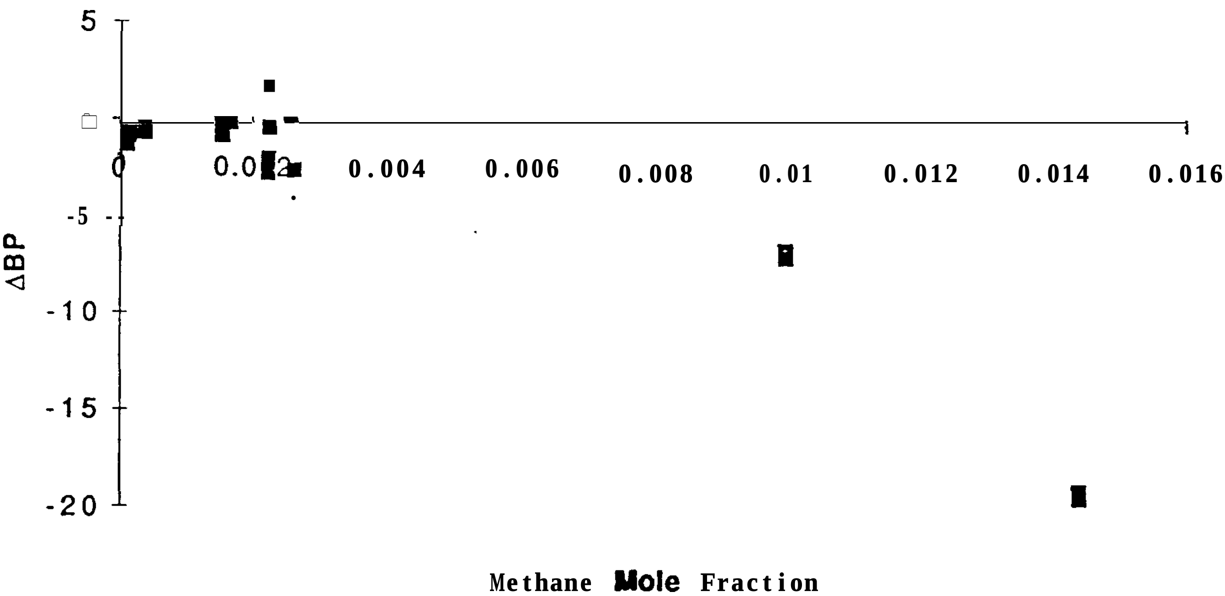

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